OPERATING EXPENSES OVERVIEW

JASON VINAGRE, MANAGER REGULATORY ACCOUNTING

1. The purpose of this evidence is to summarize Enbridge Gas's utility operating expenses and to provide a description of the evidence set out in Exhibit 4.

2. Table 1 provides the 2013 OEB-approved utility operating cost for EGD and Union and the actual utility operating cost from 2013 to 2018 for EGD and Union. Table 2 provides actual utility operating cost for 2019 to 2021 and the 2022 Estimate, 2023 Bridge Year and 2024 Test Year Forecast of utility operating cost for Enbridge Gas.

Table 1
Utility Operating Cost Summary - EGD and Union

Line No.	Particulars ($ millions)	Utility	2013 OEB-Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Gas Supply, Transportation & Storage Costs	EGD	1,342.8	1,522.8	1,644.9	1,724.3	1,497.1	1,668.0	1,566.0
2	Operating, Maintenance & Administrative Costs	EGD	414.9	410.9	408.0	430.7	449.7	431.5	436.1
3	Depreciation Expense	EGD	279.3	278.0	255.9	259.7	292.7	301.3	294.7
4	Other Financing	EGD	2.3	2.4	2.3	3.4	3.2	2.8	2.2
5	Income Tax	EGD	51.9	48.2	6.1	19.4	17.3	1.0	38.1
6	Property Tax	EGD	39.3	40.0	40.5	41.6	43.1	44.6	44.9
7	Total - Excluding Interest and Return		2,130.5	2,302.3	2,357.7	2,479.1	2,303.1	2,449.2	2,382.0
8	Gas Supply, Transportation & Storage Costs	Union	706.8	830.3	958.5	856.8	700.4	1,031.0	907.1
9	Operating, Maintenance & Administrative Costs	Union	383.1	381.0	379.8	383.0	397.9	413.4	446.9
10	Depreciation Expense	Union	196.4	193.0	200.4	212.2	228.4	254.9	276.9
11	Other Financing	Union	1.2	0.4	0.7	0.8	1.0	1.0	1.0
12	Income Tax	Union	8.4	25.8	24.1	15.7	4.4	(5.0)	(6.0)
13	Property Tax	Union	64.0	63.9	64.3	65.9	69.6	72.3	76.3
14	Total - Excluding Interest and Return		1,359.9	1,494.4	1,627.8	1,534.4	1,401.7	1,767.6	1,702.2

Table 2
Utility Operating Cost Summary - EGI

Line No	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	
1	Gas Supply, Transportation & Storage Costs	EGI	2,265.3	1,781.3	2,110.5	2,440.1	3,047.3	3,228.0	
2	Operating, Maintenance & Administrative Costs	EGI	914.6	948.4	920.6	963.8	1,021.7	1,046.0	/u
3	Depreciation Expense	EGI	601.7	618.2	640.1	705.4	725.3	892.0	/u
4	Other Financing	EGI	4.7	5.4	6.8	3.9	4.0	4.0	
5	Income Tax	EGI	59.9	39.2	41.8	33.7	42.1	43.8	/u
6	Property Tax	EGI	121.4	124.6	116.2	118.5	122.5	127.2	
7	Total - Excluding Interest and Return		3,967.6	3,517.1	3,836.0	4,265.5	4,962.9	5,341.0	/u

3. For the 2024 Test Year Enbridge Gas is requesting the OEB to approve utility operating cost of $5,341.0 million. /u

4. Enbridge Gas is requesting the OEB to approve various requests, forecast methodologies and related 2024 Test Year Forecasts found in Exhibit 4 as set out below:

Exhibit 4, Tab 2, Schedule 1	Gas Supply, Transportation and Storage Costs
Exhibit 4, Tab 2, Schedule 2	Gas Cost Reference Price
Exhibit 4, Tab 2, Schedule 3	Design Demands and Design Criteria
Exhibit 4, Tab 3, Schedule 1	Unaccounted for Gas
Exhibit 4, Tab 4, Schedule 1	Operating, Maintenance & Administrative Costs
Exhibit 4, Tab 5, Schedule 1	Depreciation Expense
Exhibit 4, Tab 6, Schedule 1	Income Taxes
Exhibit 4, Tab 6, Schedule 2	Property Taxes
Exhibit 4, Tab 7, Schedule 1	Parkway Delivery Obligation & Parkway Delivery Commitment Credit

5. Year-over-year operating expense amounts and variances are provided at Attachment 1. Details regarding historical actuals and the 2022 Estimate, 2023 Bridge Year and 2024 Test Year, along with explanations of year-over-year variances can be found throughout Exhibit 4.

Comparison of Utility Operating Cost - 2019 Actual & 2020 Actual

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2020 Actual Over/(Under) 2019 Actual
		(a)	(b)	(c) = (b-a)
1	Gas Supply, Transportation & Storage Costs	2,265.3	1,781.3	(484.0)
2	Operating, Maintenance & Administrative Costs	914.6	948.4	33.8
3	Depreciation Expense	601.7	618.2	16.5
4	Other Financing	4.7	5.4	0.7
5	Income Tax	59.9	39.2	(20.7)
6	Property Tax	121.4	124.6	3.2
7	Total - Excluding Interest and Return	3,967.6	3,517.1	(450.5)

Comparison of Utility Operating Cost - 2020 Actual & 2021 Actual

Line No.	Particulars ($ millions)	2020 Actual	2021 Actual	2021 Actual Over/(Under) 2020 Actual
		(a)	(b)	(c) = (b-a)
1	Gas Supply, Transportation & Storage Costs	1,781.3	2,110.5	329.2
2	Operating, Maintenance & Administrative Costs	948.4	920.6	(27.8)
3	Depreciation Expense	618.2	640.1	21.9
4	Other Financing	5.4	6.8	1.4
5	Income Tax	39.2	41.8	2.6
6	Property Tax	124.6	116.2	(8.4)
7	Total - Excluding Interest and Return	3,517.1	3,836.0	318.9

Comparison of Utility Operating Cost - 2021 Actual & 2022 Estimate

Line No.	Particulars ($ millions)	2021 Actual	2022 Estimate	2022 Estimate Over/(Under) 2021 Actual	
		(a)	(b)	(c) = (b-a)	
1	Gas Supply, Transportation & Storage Costs	2,110.5	2,440.1	329.6	
2	Operating, Maintenance & Administrative Costs	920.6	963.8	43.2	
3	Depreciation Expense	640.1	705.4	65.2	
4	Other Financing	6.8	3.9	(2.9)	
5	Income Tax	41.8	33.7	(8.1)	/u
6	Property Tax	116.2	118.5	2.4	
7	Total - Excluding Interest and Return	3,836.0	4,265.5	429.4	/u

Comparison of Utility Operating Cost - 2022 Estimate & 2023 Bridge Year

Line No.	Particulars ($ millions)	2022 Estimate	2023 Bridge Year	2023 Bridge Over/(Under) 2022 Estimate	
		(a)	(b)	(c) = (b-a)	
1	Gas Supply, Transportation & Storage Costs	2,440.1	3,047.3	607.1	
2	Operating, Maintenance & Administrative Costs	963.8	1,021.7	57.9	/u
3	Depreciation Expense	705.4	725.3	19.9	/u
4	Other Financing	3.9	4.0	0.1	
5	Income Tax	33.7	42.1	8.4	/u
6	Property Tax	118.5	122.5	4.0	
7	Total - Excluding Interest and Return	4,265.5	4,962.9	697.5	/u

Comparison of Utility Operating Cost - 2023 Bridge Year & 2024 Test Year

Line No.	Particulars ($ millions)	2023 Bridge Year	2024 Test Year	2024 Test Over/(Under) 2023 Bridge	
		(a)	(b)	(c) = (b-a)	
1	Gas Supply, Transportation & Storage Costs	3,047.3	3,228.0	180.8	
2	Operating, Maintenance & Administrative Costs	1,021.7	1,046.0	24.3	/u
3	Depreciation Expense	725.3	892.0	166.7	/u
4	Other Financing	4.0	4.0	0.0	
5	Income Tax	42.1	43.8	1.7	/u
6	Property Tax	122.5	127.2	4.7	
7	Total - Excluding Interest and Return	4,962.9	5,341.0	378.1	/u

GAS SUPPLY, TRANSPORTATION & STORAGE COSTS

JASON GILLETT, DIRECTOR GAS SUPPLY
STEVE DANTZER, MANAGER GAS SUPPLY PLANNING
DAVE JANISSE, MANAGER GAS SUPPLY ACQUISITIONS
RACHEL GOODREAU, MANAGER REVENUE AND COST OF GAS

1. The purpose of this evidence is to request OEB approval of the 2024 Test Year Forecast of gas costs. The Gas Cost to Operations Schedule is provided at Attachment 1 and includes the 2024 Test Year Forecast of gas costs based on the 2024 Gas Supply Plan, as well as other gas costs and adjustments as provided in Section 1.5. In addition to the gas costs included in the 2024 Test Year Forecast, Enbridge Gas is also seeking OEB approval of the cost associated with adding 10 PJ of market-based storage. Costs associated with this storage are not included in the Gas Cost to Operations Schedule provided at Attachment 1 and are estimated to be approximately $4 million each year over the IR term. This is further discussed in Section 2.

2. For purposes of developing the 2024 Gas Supply Plan, Enbridge Gas has used the most recent information available at the time of filing this Application, including the existing transportation and storage contracts provided in Section 1.4. To capture the costs of uncontracted assets, Enbridge Gas has included an estimate of costs associated with incremental 2024 transportation and storage requirements. Any variances between forecast and actual transportation and storage costs are proposed to be captured in the respective deferral and variance accounts, which are provided at Exhibit 9, Tab 1, Schedule 2.

3. Enbridge Gas will not contract for these uncontracted assets until OEB approval is received. Pending OEB approval, Enbridge Gas will continue to monitor any shortfalls and will use the best available information at that time to make contracting decisions. Enbridge Gas will continue to follow The Report of the Ontario Energy Board: Framework for the Assessment of Distributor Gas Supply Plans (Framework) and provide updates to the OEB according to the Framework's requirements.

4. This evidence includes a review of the load balancing portfolio, as agreed to by Enbridge Gas in the 2021 Annual Update and subsequently in the Settlement Proposal for the 2020 Utility Earnings and Disposition of Deferral and Variance Account Balances proceeding[1]. Enbridge Gas engaged ICF International, Inc. (ICF) to assist with the evaluation of the appropriate mix of storage as compared to winter supply purchases and delivered supply alternatives as part of its load balancing portfolio.

5. Enbridge Gas is requesting OEB approval to hold a total of 28 PJ of market-based storage throughout the IR term, of which 18 PJ was identified using the aggregate excess calculation and 10 PJ that was recommended as part of the ICF analysis. Enbridge Gas has reflected the 18 PJ of storage requirements identified through the calculation of aggregate excess in the 2024 forecast of gas costs. Due to the timing of the ICF engagement, the cost associated with the 10 PJ of market-based storage is not included in 2024 gas costs and is proposed to be recovered in the Market-Based Storage Variance Account. This variance account is provided at Exhibit 9, Tab 1, Schedule 2.

[1] EB-2021-0149, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, October 4, 2021, pp.11-12.

6. As noted in this Exhibit, the timing between receiving an OEB decision on this Application and Enbridge Gas's implementation of changes to its gas supply portfolio is expected to result in gas cost deferral and variance account balances. This Application reflects proposed gas costs in rates effective January 1, 2024. However, Enbridge Gas does not anticipate receiving an OEB decision with sufficient time to reflect contracting changes in advance of the 2023/2024 gas year. Enbridge Gas estimates that the earliest that an OEB decision can be implemented would be for the 2024/2025 gas year. Enbridge Gas estimates that contracting changes for transportation services would be implemented for November 1, 2024, and contracting for storage services would be implemented for April 1, 2024. Therefore, Enbridge Gas anticipates that variances between January 1, 2024, and November 1, 2024, will be included in the respective variance and deferral accounts, as outlined throughout Exhibit 9.

7. Throughout the IR term, Enbridge Gas will continue to follow the Quarterly Rate Adjustment Mechanism (QRAM) process to adjust gas costs. Further detail on the QRAM process and a description of the associated impacts from harmonization on the QRAM are provided in Section 3. The QRAM process uses a reference price to price components of gas costs that are part of the revenue requirement for the 2024 Test Year. Further detail on the proposed harmonized reference price is provided at Exhibit 4, Tab 2, Schedule 2.

8. Enbridge Gas's next 5-year Gas Supply Plan is due to be filed with the OEB in early 2024. As noted above, Enbridge Gas anticipates that the earliest it can implement an OEB decision on this Application is November 1, 2024. As a result, Enbridge Gas plans to request a 1-year extension on the deadline to file its next 5-Year Gas Supply Plan as part of the 2023 Annual Update. This approach is consistent with

OEB Staff recommendations in the OEB Staff Report to the Ontario Energy Board as part of the 2022 Annual Update[2], as OEB Staff noted that "filing a five-year GSP without the critical updated determinants from the rebasing application will not serve its intended purpose" [3]. This extension provides the opportunity for Enbridge Gas to reflect and incorporate decisions and approvals from this Application into an updated 5-Year Gas Supply Plan.

9. An overview of Enbridge Gas's response to energy transition is provided at Exhibit 1, Tab 10, Schedules 1-8. Adjustments to reflect the transition to a lower-carbon economy are incorporated into upstream processes (such as demand forecasting and integrated resource planning) that feed into the Gas Supply Plan. As a result, the Gas Supply Plan reflects the impacts of these assumptions on demands but does not include any additional energy transition adjustments.

10. This evidence is organized as follows:
    1. Gas Supply Plan
    2. Load Balancing Portfolio Assessment
    3. QRAM & Gas Supply Variance Accounts
    4. Implementation

<u>1. Gas Supply Plan</u>

11. The requirements of the Framework and the gas supply planning guiding principles have not changed as a result of harmonization. Likewise, customer demands and growth are still based on geographic location and the TransCanada distributor

[2] EB-2022-0072.
[3] EB-2022-0072, OEB Staff Report to the Ontario Energy Board, September 7, 2022, p.26.

delivery areas remain unchanged[4]. Enbridge Gas will continue to use the execution strategies as discussed in the 5-Year Gas Supply Plan and Annual Updates to manage changes in customer demand that occur each year.

1.1. Notable Changes

12. Since amalgamation, Enbridge Gas has been harmonizing gas supply planning and procurement processes and policies. Information related to these harmonization efforts are detailed in the Continuous Improvement Strategies section of each Annual Update[5].

13. The following is a list of notable changes to processes that impact the Gas Supply Plan and are included in this Application. These impacts are reflected in the 2024 Test Year and are addressed throughout this evidence:
    a) Changes to annual demand forecast methodologies, as provided at Exhibit 3, Tab 2, Schedules 2-8;
    b) Harmonization of design day methodologies, provided at Exhibit 4, Tab 2, Schedule 3;
    c) Harmonization of operational contingency planning assumptions, provided at Exhibit 4, Tab 2, Schedule 4;
    d) Updated storage deliverability parameters provided at Exhibit 4, Tab 2, Schedule 5; and
    e) Changes to the approach used to track and record gas supply costs as a result of harmonization of Gas Supply Deferral and Variance Accounts provided at Exhibit 9, Tab 1, Schedule 2.

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[4] As the operator of the Canadian Mainline system, TransCanada has sole discretion as to how delivery areas are established. The current delivery areas are not expected to change prior to the end of the current Mainline settlement in 2026. Any changes that TransCanada may make to the delivery areas will require approval from the Canada Energy Regulator.
[5] EB-2020-0135; EB-2021-0004; and EB-2022-0072.

1.2. Gas Supply Planning Objectives and Principles

14. The objective of the Gas Supply Plan is to identify an efficient combination of upstream transportation, supply purchases, and storage assets to meet sales service and bundled direct purchase (DP) customers' annual, seasonal and design day natural gas delivery requirements while adhering to the OEB's gas supply planning guiding principles as outlined in the Framework. The gas supply planning guiding principles are:

- Cost-effectiveness – The gas supply plans will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.
- Reliability and security of supply – The gas supply plans will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and seasonal gas delivery requirements.
- Public policy – The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.[6]

15. As outlined in the 5-Year Gas Supply Plan and successive Annual Updates, Enbridge Gas adheres to these principles by maintaining a diverse portfolio with respect to supply basins, receipt points, counterparties, contract terms, and upstream transportation and storage services. This approach allows Enbridge Gas to effectively manage costs while maintaining the flexibility to adjust to changes in market conditions and customer demands. Balanced consideration of these

[6] EB-2017-0129, Report of the Ontario Energy Board, October 25, 2018, pp.7-8.

principles ensures Enbridge Gas customers have access to secure and reliable natural gas at a prudently incurred cost.

1.3. Gas Supply Planning Process

16. The common starting point in developing the Gas Supply Plan is the creation of a demand forecast; an analysis that focuses on key factors impacting demand including customer growth, weather, design day requirements, customer consumption patterns, economic conditions and impacts of energy transition.

17. Subsequently, Enbridge Gas must consider the appropriate quantity of upstream transportation and storage assets required to meet the annual, seasonal, and design day demands of sales service and bundled DP customers. The Gas Supply Plan does not include any excess assets, only those necessary to meet firm customer requirements.

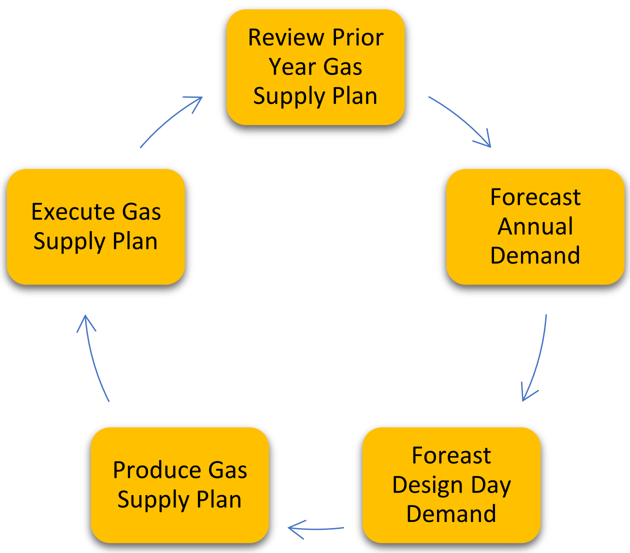
18. Enbridge Gas optimizes existing storage and transportation assets to determine the optimal mix of commodity purchases and storage utilization to meet its forecasted demand requirements and identify any shortfalls in upstream assets.

19. The final step in the planning process is the execution of the Gas Supply Plan which includes the evaluation of transportation, supply, and storage options. This evaluation must have a long-term strategic focus, taking into consideration future growth and asset requirements by analyzing each decision as part of a balanced portfolio which adheres to the guiding principles. Enbridge Gas will execute on its Gas Supply Plan by contracting for any assets required, then implementing a layered approach to procuring supply at various points. Supply purchase decisions are made regularly

throughout the year to allow Enbridge Gas to continuously update its supply purchase plan to account for changes in market conditions and customer demands.

20. Figure 1 summarizes this planning process.

Figure 1: Annual Gas Supply Planning Process



21. Each year, the Gas Supply Plan is finalized and receives executive approval in the third quarter. The results of the Gas Supply Plan are communicated to key stakeholders throughout Enbridge Gas to support ongoing operations.

22. With OEB approval, beginning in 2024, Enbridge Gas will create and operationalize the Gas Supply Plan as one integrated utility without separate rate zones for EGD, Union North and Union South.

1.4. Gas Supply Plan

23. The 2024 Test Year Gas Supply Plan and 2023 Bridge Year Gas Supply Plan were completed in the second quarter of 2022 and use a monthly commodity price forecast based on the April 1, 2022, QRAM commodity price, provided at Attachment 2, and upstream transportation tolls in effect as of April 30, 2022, provided at Attachment 3. Tolls on the TransCanada Mainline are subject to the 2021 to 2026 Canadian Mainline Settlement Agreement and tolls beyond that period will be subject to review by the Canada Energy Regulator.

24. The 2023 Gas Supply Plan is based on OEB-approved methodologies including demand forecasting and design day methodologies, as well as existing rate zones.

25. The annual demand and supply balance for the 2024 Test Year compared to the 2023 Bridge Year is provided in Table 1.

Table 1
Comparison of Annual Gas Supply / Demand Position

Line No.	Particulars (TJ)	2023 Bridge Year	2024 Test Year	2024 Test Over/(Under) 2023 Bridge
		(a)	(b)	(c) = (b-a)
	Demand			
1	Total Demand	764,328	772,904	8,576
	Supply			
2	Appalachia	100,125	100,399	274
3	Chicago	71,242	71,438	195
4	Niagara	80,651	80,923	273
5	Ontario / Dawn (1)	132,639	126,720	(5,920)
6	U.S. Mid-Continent	21,950	22,011	60
7	Unsecured	41	7,056	7,015
8	Western Canadian Sedimentary Basin	114,640	118,685	4,046
9	Total System Supply	521,288	527,231	5,943
10	Direct Purchase Deliveries	244,120	245,246	1,126
11	Storage (Injection) / Withdrawal	(1,080)	427	1,507
12	Total Supply	764,328	772,904	8,576

Note:
(1) Includes local production and delivered supply.

26. The design day demand and supply balance is provided at Attachment 4. Table 2 provides a comparison of the design day demand for the 2024 Test Year compared to the 2023 Bridge Year. The design day demand for 2024 in Table 2 differs from the design day demand provided at Exhibit 4, Tab 2, Schedule 3, Table 3 as Table 2 excludes unbundled customer design day demands and includes fuel and Union North t-service customer design day demands.

Table 2
Comparison of Design Day Position

Line No.	Particulars (TJ/d)	2023 Bridge Year	2024 Test Year	2024 Test Over/(Under) 2023 Bridge
		(a)	(b)	(c) = (b-a)
1	Design Day Demand	7,945	8,062	118
	Supply			
2	Great Lakes	21	21	0
3	In-franchise Supply	5,277	5,032	(246)
4	NEXUS	106	158	53
5	Panhandle	60	60	0
6	TCPL Long Haul	354	358	4
7	TCPL Short Haul	1,454	1,454	0
8	TCPL STS	519	519	0
9	Vector	106	311	206
10	Total	7,897	7,914	17
11	Supply Excess / (Shortfall)	(47)	(148)	(101)

27. In the 2024 Test Year (Attachment 4, page 2, line 12), there is a 157.6 TJ/d shortfall in the Enbridge CDA, 11.1 TJ/d excess in the Enbridge EDA and 1.8 TJ/d shortfall in the Union WDA. The excess upstream assets in the Enbridge EDA will be used to reduce the shortfall in the Enbridge CDA. The remaining shortfall in the Enbridge CDA is planned to be managed with third-party services and will be reviewed on an annual basis. The Union WDA shortfall is planned to be managed with a combination of long-haul transportation and third-party services. For purposes of determining 2024 Rates, Enbridge Gas has included estimated costs of upstream assets required to meet the above-described shortfalls which have been included in the Gas Cost to Operations Schedule provided at Attachment 1. As outlined above, any difference between estimated and actual costs will be

addressed through the disposition of variance account balances in the applicable QRAM proceeding. No contracting decisions will be made until there is an OEB decision on this Application. Enbridge Gas will continue to monitor any shortfalls and will use the best available information at that time to make any contracting decisions. Enbridge Gas will continue to follow the OEB gas supply planning process and file decisions according to the requirements under the Framework.

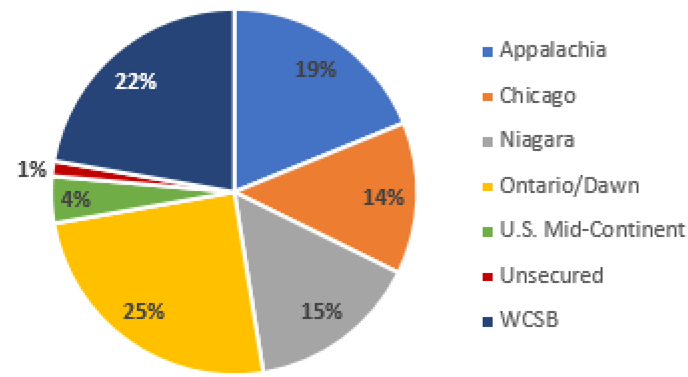
28. The following sections outline the gas supply sources, transportation paths and storage targets used by Enbridge Gas in the 2024 Gas Supply Plan.

Commodity Portfolio

29. Enbridge Gas procures supply on behalf of its sales service customers. The commodity portfolio reflects many years of planning which leverages much of the North American natural gas supply market, including supply from sources in the Western Canadian Sedimentary Basin, Dawn, Chicago, Niagara, U.S. Mid-Continent, and the Appalachian Basin. These supply sources, along with the Enbridge Gas transportation contracts which move gas supplies to both the distribution system and storage assets, have resulted in a commodity portfolio which is diverse, flexible, reliable, and cost-effective.

30. Figure 2 provides an illustration of the sources of supply for sales service customers in the Gas Supply Plan for the 2024 Test Year.

Figure 2: 2024 Sources of Supply



31. Within the commodity portfolio, Enbridge Gas procures renewable natural gas (RNG) as part of the OEB-approved Voluntary RNG Program[7]. As indicated in the 2022 Annual Update, Enbridge Gas procured 1,000 GJ of RNG using funds collected in this program to cover the cost premium of RNG over conventional natural gas. Enbridge Gas has proposed changes to this program to facilitate procuring additional RNG into the commodity portfolio as provided at Exhibit 4, Tab 2, Schedule 7. As these costs are not anticipated until 2025, they have not been included in the 2024 Test Year Forecast.

32. Within the commodity portfolio, Enbridge Gas also procures hydrogen as part of the OEB-approved Low Carbon Energy Project[8] (LCEP), which began blending hydrogen in October 2021. Enbridge Gas procured the equivalent of 143 GJ of hydrogen in 2021 and the equivalent of 1,125 GJ through the first half of 2022. There were no additional gas costs associated with the purchase of this hydrogen. Further details on Enbridge Gas's plans for hydrogen are provided at Exhibit 4, Tab 2, Schedule 6.

[7] EB-2020-0066.
[8] EB-2019-0294.

Transportation Portfolio

33. Enbridge Gas holds a diverse portfolio of transportation contracts to meet the design day needs of each delivery area. The transportation portfolio of firm services provides direct and secure access to a diverse group of supply basins and market hubs across North America.

34. Attachment 5 is a visual representation of the combined transportation contracts that Enbridge Gas holds to serve its delivery areas. A complete listing of the transportation capacity currently contracted is provided at Attachment 3.

35. Enbridge Gas uses transportation capacity on the Dawn Parkway System to transport supply from Dawn to serve the Enbridge CDA and Enbridge EDA. Prior to rebasing, the cost of the Dawn Parkway System transportation was charged to the EGD rate zone by the Union rate zones to recognize the contracts that existed between EGD and Union prior to amalgamation. Upon rebasing, the Dawn Parkway System costs are no longer treated as gas supply costs of the EGD rate zone and will instead be part of rate base and recovered within delivery rates. This change in 2024 has been reflected in the gas costs (Attachment 1). Similarly, there is an offsetting reduction in regulated revenue provided at Exhibit 3, Tab 4 Schedule 1, relating to storage and transportation revenue and upstream transportation optimization.

36. Enbridge Gas holds third-party transportation contracts that are used to meet in-franchise demands on the distribution system for both sales service and DP customers. Enbridge Gas proposes to allocate the costs of these transportation contracts, provided in Table 3, to in-franchise rate classes for recovery in delivery rates consistent with purpose of the contracts. This proposal is consistent with

Union's approach for the costs of the two St. Clair Pipelines L.P. contracts that are recovered in in-franchise delivery rates. Further contract details are provided at Attachment 3.

Table 3
Other Third-Party Transportation Contracts

Line No.	Particulars (GJ/d)	Path	Contract Quantity
			(a)
	Upstream Pipeline/Transportation Service		
1	Centra Transmission Holdings Inc. & Centra Pipelines Minnesota Inc.	Sprague to Union MDA	5,813
2	TransCanada Pipeline	Kirkwall to Union CDA	135,000
3	TransCanada Pipeline	Dawn to Union ECDA	8,000
4	St. Clair Pipelines L.P.	St. Clair Crossing	214,000
5	St. Clair Pipelines L.P.	Bluewater Crossing	127,000
6	2193914 Canada Limited	Vaughan to Lisgar	244,265

37. The Centra Transmission Holdings Inc. & Centra Pipelines Minnesota Inc. contracts allow for deliveries of gas into Fort Frances within the Union MDA. The Kirkwall to Union CDA contract supports the delivery of gas into the Hamilton System and Brantford Nanticoke System and are fully utilized on the design day. The Dawn to Union ECDA contract is required by TransCanada to maintain flow into Enbridge Gas's system in Burlington. The St. Clair Pipeline capacity for both St. Clair and Bluewater river crossings are required to support imports of gas from the international border into Enbridge Gas's system. Finally, the capacity contracted with 2193914 Canada Limited is required to move gas to Brampton and the Greater Toronto Area on the design day.

Storage Portfolio

38. The inclusion of storage assets in the Gas Supply Plan provides a cost-effective, reliable, and secure alternative to purchasing commodity when required by customers, which is consistent with the OEB's guiding principles.

39. In accordance with the Natural Gas Electricity Interface Review (NGEIR) Decision[9] and confirmed in the OEB's Decision and Order regarding the amalgamation of EGD and Union and the associated rate-setting mechanism[10], the amount of cost-based storage reserved for EGD rate zone customers is 99.4 PJ and 100 PJ is reserved for Union rate zone customers for a combined 199.4 PJ for all Enbridge Gas in-franchise customers[11].

40. Previously, Union rate zone customers had excess utility storage space that was sold short term at market-based rates. Beginning in 2024, the excess utility storage space that previously existed in the Union rate zones will be used to serve all Enbridge Gas in-franchise customers.

41. The storage space required for sales service and bundled DP customers, under weather normal conditions, is determined using the aggregate excess methodology. This methodology calculates the difference between forecasted winter demand (November 1 through March 31) and the annual average daily demand for a 151-day period. The result is the required storage space allocation.

42. Aggregate Excess = Forecasted Winter Consumption – [(Total Annual Consumption x 151/365)]

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[9] EB-2005-0551, Decision with Reasons, November 7, 2006.
[10] EB-2017-0306/0307, OEB Decision and Order, August 30, 2018.
[11] Included in this amount is 15 PJ of capacity for t-service customers.

43. In addition to calculating aggregate excess for sales service and bundled DP customers, the storage requirement also includes cost-based service contracted by Union South t-service customers. The following four storage allocation methodologies are used to calculate the maximum storage space available to contract for by Union South t-service customers:
    a) Aggregate excess;
    b) 15 x obligated daily contract quantity (DCQ);
    c) Peak hourly consumption x 24 x 4 days; or,
    d) Contract demand x 10.

44. As provided at Exhibit 4, Tab 2, Schedule 4, Union planned for operational contingency requirements within its portfolio of cost-based storage in addition to the storage requirements determined by the aggregate excess calculation. EGD managed operational contingency requirements through cost-based storage injection and withdrawal targets rather than procuring incremental storage space for operational contingency purposes. Effective 2024, Enbridge Gas plans to adopt the approach of managing operational contingency using cost-based storage inventory targets and has incorporated the storage space and molecule requirements provided at Exhibit 4, Tab 2, Schedule 4 in the Gas Supply Plan. Within the portfolio of storage space and gas inventory, both space and molecules are held in reserve so that these assets are available for operational contingency purposes; 4.8 PJ of storage space are held for operational contingency on November 1 each year and 10.8 PJ of gas supply inventory is reserved on March 31 each year. As a result, these storage space and inventory amounts reduce the assets available to meet in-franchise demand requirements accordingly.

45. Table 4 illustrates the 217.7 PJ of in-franchise storage space requirements that have been included in proposed rates for 2024 as well as the 10 PJ of storage recommended by ICF that was not included in rates for 2024. The total storage space of 217.7 PJ was determined using the aggregate excess calculation of 202.7 PJ and t-service storage requirement of 15 PJ. As provided in Section 2, Enbridge Gas plans to hold 10 PJ of market-based storage in addition to the 18 PJ reflected in 2024 Rates. Due to the timing of the engagement with ICF, Enbridge Gas was not able to include the costs related to the additional 10 PJ of market-based storage in 2024 Rates and therefore is requesting OEB approval of the annual incremental costs over the IR term that will be recovered in the Market-Based Storage Variance Account.

Table 4
In-franchise Storage Space Included in 2024 Test Year

Line No.	Particulars (PJ)	2023 Bridge Year	2024 Test Year
		(a)	(b)
	In-franchise Storage in Rates		
1	Aggregate Excess	197.9	202.7
2	T-Service Storage	14.9	15.0
3	Operational Contingency	9.5	N/A[12]
4	Total Storage in Rates	222.3	217.7
	Cost-Based Storage in Rates		
5	Dawn (1)	96.5	100.0
6	Tecumseh	99.4	99.4
7	Crowland	0.3	0.3
8	Total Cost-Based Storage	196.2	199.7
	Market-Based Storage		
9	Market-Based Storage in Rates	26.1	18.0
10	Total Storage in Rates	222.3	217.7
11	Incremental Storage Space (2)	-	10.0
12	Total Storage Space	222.3	227.7

Notes:
(1) 2023 includes excess utility space.
(2) Based on ICF analysis in Section 2.

46. The impact of the storage deliverability proposal provided at Exhibit 4, Tab 2, Schedule 5, is a 0.3 PJ loss in deliverability on the design day. At this time,

[12] As noted above, effective January 1, 2024, Enbridge Gas will utilize cost-based storage injection and withdrawal targets rather than procuring incremental storage space for operational contingency purposes.

Enbridge Gas does not plan to purchase incremental storage capacity to account for the loss of deliverability and will instead rely upon supply purchases at Dawn to replace the deliverability shortfall. As part of the execution of the Gas Supply Plan, Enbridge Gas will continue to monitor inventory positions and will make purchasing decisions as needed.

47. Enbridge Gas proposes to hold a total of 28 PJ of market-based storage for April 1, 2024, which is an increase of 1.9 PJ from the 2023 Bridge Year market-based storage volume. This includes 18 PJ from Table 4, line 9 and 10 PJ from Table 4 line 11 (see Section 2 for further details on the ICF recommendation). Each year Enbridge Gas conducts a blind request for proposal process to acquire market-based storage services. The actual cost of procuring this market-based storage will be captured through the Market-Based Storage Variance Account.

1.5. Gas Cost to Operations and Gas Supply Volumes

48. Attachment 1, pages 1-2 provides a summary of 5 years of historical gas costs, as well as the forecast of gas costs for the 2022 Estimate, 2023 Bridge Year and 2024 Test Year.

49. The summary of gas costs provided at Attachment 1, pages 1-2 provides details of supply, transport and other gas costs and adjustments. The other gas costs and adjustments include the following components:
    a) Gas deferral adjustment is comprised of variances between the actual gas supply costs and the forecast gas supply costs that underpin the rates approved in the QRAM. The gas supply cost variances are recorded in the PGVA for the respective rate zones for the years 2017 to 2023;

b) Storage (injection)/withdrawal costs are comprised of the cost associated with the net injections to/withdrawals from storage to balance the difference between annual gas supply and annual demand;
c) Market-based storage costs are comprised of storage costs incurred for the storage capacity to required to meet in-franchise storage requirements;
d) Parkway delivery commitment incentive (PDCI) costs are comprised of the amount paid to DP customers with a Parkway delivery obligation to recognize the incremental costs incurred by customers to deliver gas at Parkway. A description of PDCI is provided at Exhibit 4, Tab 7, Schedule 1;
e) Dawn Parkway transportation costs pertain to the transportation requirements on the Dawn Parkway System for the in-franchise customers in the EGD rate zone. As provided in Section 1.4, the Dawn Parkway transportation costs will no longer be treated as gas supply costs of the EGD rate zone and will instead be part of rate base and recovered within delivery rates in 2024;
f) Transportation optimization are costs relating to optimizing upstream transportation assets. The corresponding revenues are provided Exhibit 3, Tab 4, Schedule 1;
g) Other adjustments is comprised of adjustments such as UDC prospective recovery, heat value adjustments and foreign exchange adjustments;
h) Cap and trade/federal carbon is comprised of federal carbon facility costs associated with transmission and storage;
i) Unregulated costs include the elimination of the gas costs associated with unregulated UFG, compressor fuel, company use and federal carbon facility costs; and
j) Affiliate adjustment includes the elimination of the gas costs associated with the Dawn Parkway transportation costs as discussed in part (e).

50. Attachment 1 also includes the details of the proposed cost consequences of the 2024 Gas Supply Plan, including the forecast gas supply, transportation and storage costs, the calculation of load balancing costs for 2024 as well as a comparison of gas supply and demand for 2024 system gas forecast.

51. Attachment 7 provides five years of historical gas supply volumes, as well as the forecast for the 2022 Estimate, 2023 Bridge Year and 2024 Test Year.

52. Year-over-year variances for gas cost to operations are driven primarily by changes in purchase volumes (which are the result of variances in demand, largely driven by weather), natural gas market prices, and the gas supply portfolio. Volume variances and changes to the gas supply portfolio between 2019 and 2022 are discussed in the Enbridge Gas 5 Year Gas Supply Plan[13] and each of the subsequent Annual Gas Supply Plan Updates[14]. The proposed 2024 Gas Supply Plan and notable changes relating to commodity, transportation and storage have been addressed in Section 1.4.

2. Load Balancing Portfolio Assessment

53. Load balancing is the practice of delivering supply that is above or below average day demand through the year. Enbridge Gas manages planned load balancing requirements for system and bundled DP customers through a combination of withdrawals from and injections into storage and purchases of gas supply at Dawn. On an actual basis, load balancing requirements may be higher than planned due to customer demand being above normal. Enbridge Gas will manage these

[13] EB-2019-0137.
[14] EB-2020-0135, EB-2021-0004, EB-2022-0072.

unplanned load balancing requirements for system customers only. Unplanned load balancing requirements may be met through storage withdrawals, incremental supply purchases, and third-party services. Bundled DP customers will be responsible for their own unplanned load balancing requirements through their obligation to meet their checkpoints at the end of February and September each year. More information on DP customer load balancing requirements is provided at Exhibit 8, Tab 4, Schedule 3.

54. Enbridge Gas agreed to provide more information on its use of storage within in its load balancing portfolio as part of the 2024 Rebasing proceeding during the 2021 Annual Update, and subsequently during the Settlement Proposal for the 2020 Utility Earnings and Disposition of Deferral and Variance Account Balances Application[15]:

> In connection with the settlement of this item, Enbridge has agreed to file evidence in its rebasing application (for rates as of January 1, 2024, which will include requests for approvals for the pass-through of gas supply costs) demonstrating that it has fully considered the opportunity to reduce storage costs through inclusion, as part of its load balancing portfolio, of cost-effective market-based alternatives to the purchase of third-party storage. That evidence will include consideration of: (i) the cost of delivered supply (including the commodity cost) in winter in lieu of contracting for additional storage: versus (ii) the cost (savings) of buying gas in summer and the associated additional storage and related costs required to store and redeliver that gas in the winter.

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[15] EB-2021-0149, Settlement Proposal, October 4, 2021, pp. 11-12.

55. In response, Enbridge Gas engaged ICF to assist with the evaluation of the appropriate mix of storage as compared to delivered supply in the winter as part of its load balancing portfolio. The ICF Report is provided at Attachment 6.

56. The starting point for the ICF analysis is based on Enbridge Gas's load balancing requirements calculated using aggregate excess and a weather normal demand forecast resulting in approximately 203 PJ of storage required for 2024 (see Table 4, line 1). In order to evaluate the economic impact of changes to Enbridge Gas's storage portfolio compared to winter commodity purchases, ICF evaluated the impact of different levels of storage capacity and delivered services on total supply portfolio costs using various commodity pricing scenarios.

57. ICF evaluated the economic impacts of Enbridge Gas holding 198 PJ of total storage, which is 5 PJ less than the 2024 aggregate excess requirement of 203 PJ. ICF concluded that this scenario resulted in average annual portfolio cost increases between $0.2 million to $11 million, depending on the weather scenario evaluated as provided at Attachment 6, Exhibit 3-1.

58. ICF also evaluated multiple scenarios under which Enbridge Gas held various levels of storage equal to and above the 203 PJ calculated using aggregate excess. In Attachment 6, Exhibit 4-9, ICF concluded that holding storage above aggregate excess would result in average annual portfolio cost reductions in all weather scenarios evaluated.

59. As a result, in Attachment 6, page 46, ICF recommends that in addition to the 203 PJ storage requirements calculated using the aggregate excess methodology, Enbridge Gas should consider adding incremental market-based storage of 10 PJ over the IR term:

> ICF recommends the 10 PJ of incremental storage capacity as the best balance between the projected value of the incremental storage capacity to minimize gas supply costs, the value of reducing gas cost uncertainty and volatility, and the reliability benefits provided by storage capacity, and the fixed cost commitments needed to contract for the storage capacity.

60. In addition to economic benefits of holding incremental storage, on page 46, ICF also highlights other benefits to the Gas Supply Plan resulting from holding incremental storage:

> In addition, the incremental storage capacity would increase system reliability and resiliency and is expected to lead to additional cost savings due to the flexibility in gas purchase timing facilitated by the incremental storage capacity.

61. As noted above, Enbridge Gas has reflected a total of 217.7 PJ of storage in 2024 gas costs, which consists of 199.7 PJ of cost-based storage and 18 PJ of market-based storage. However, based on ICF's recommendation, Enbridge Gas is seeking OEB approval for cost consequences related to holding an additional 10 PJ of market-based storage throughout the IR term. This would result in Enbridge Gas contracting for a total of 28 PJ of market-based storage in 2024. The difference between the proposed amount of market-based storage of 28 PJ and the amount included in 2024 gas costs is proposed to be included in the Market-Based Storage Variance Account. The estimated cost of an incremental 10 PJ of storage is $10 million; however, this will be partially offset by approximately $6 million of commodity savings as a result of holding this incremental storage. The net impact of this proposal is estimated to be an additional $4 million annually on a planned

basis over the IR term, which results in minimal[16] bill increases for the typical residential sales service customer. As referenced above, the estimated savings of $6 million are based on a weather normal scenario. As outlined in the ICF Report, the economic benefits related to this incremental storage are increased when evaluated under different pricing scenarios which more than offset the cost of the storage.

62. On a planned basis, the Enbridge Gas supply purchases continue to be weighted within the year to winter purchases. Enbridge Gas plans to use purchases at Dawn to meet planned load balancing requirements in the winter months. In addition, a significant portion of unplanned load balancing requirements will also be met using purchases at Dawn beyond planned winter amounts. Gas purchases are not as flexible as storage services for changes within the day and carry additional risk with respect to pricing and availability of supply. For this reason, Enbridge Gas uses a combination of winter supply purchases, peaking services, and the deliverability available from both cost-based and market-based storage. This diversified portfolio results in a reliable and cost-effective suite of assets to support customer load balancing requirements.

3. QRAM & Gas Supply Variance Accounts

63. Enbridge Gas uses the QRAM to set reference prices for commodity and upstream transportation. The existing QRAM process for the EGD and Union rate zones was reviewed and approved as part of the QRAM review[17]. In order to align with the harmonization to a single Gas Supply Plan and a harmonized reference price, as

[16] Less than 25 cents per year for the average sales service customer.
[17] EB-2008-0106.

provided at Exhibit 4, Tab 2, Schedule 2, Enbridge Gas will harmonize and consolidate the QRAM schedules for the amalgamated utility.

64. The harmonized QRAM will include:
    a) Determination of a common weighted average reference price;
    b) Gas supply deferral and variance accounts (QRAM);
    c) Updates on upstream toll and tariff changes, as approved by applicable regulatory bodies;
    d) Updates to the return on working capital (gas in storage) to reflect the impact of reference price changes; and
    e) An efficient, consistent, and mechanical filing and approval process.

65. The weighted average reference price calculation is derived from the weighted average cost of the harmonized gas supply portfolio based upon a 21-day average of various indices for a 12-month forecasting period. The methodology for reference price adjustment and forecast period is currently aligned for both EGD and Union rate zones. Details on the harmonized reference price are provided at Exhibit 4, Tab 2, Schedule 2.

66. The gas supply variance accounts provide the means of tracking and clearing variances between the forecast cost of gas and the actual cost of gas. The associated variances will be recorded in the harmonized gas supply deferral and variance accounts to ensure customers and Enbridge Gas are held whole with respect to cost of gas. Details of the harmonized gas supply deferral and variance accounts are provided at Exhibit 9, Tab 1, Schedule 2.

67. Enbridge Gas is proposing to consolidate the existing UDC deferral account used to track costs for Union rate zone customers into a harmonized Third-Party

Transportation Variance Account which will facilitate the recovery of variances between costs included in rates and actual costs of upstream transportation, including costs related to unutilized capacity. This proposal does not result in a change to the total costs that are recovered from ratepayers but rather the timing of recovery of variances associated with unutilized capacity. The Third-Party Transportation Variance Account will be disposed on a quarterly basis within QRAM. This allows for more timely alignment between costs and expenses for customers. The key function of the UDC deferral account was to track cost recovery and drivers to allocate the costs of actual unutilized capacity appropriately between rate zones. With the proposed single rate zone, this allocation will no longer be necessary. For further information on consolidation of the UDC deferral account, please see Exhibit 9, Tab 1, Schedule 2.

4. Implementation

68. The evidence in this Exhibit assumes the costs are effective January 1, 2024. However, given the timing of an OEB decision, adjustments to the Gas Supply Plan as a result of the Application will not be effective until November 1, 2024, as this would be the first opportunity to procure assets based on approval from the OEB. As provided in Section 1.3 above, the Gas Supply Plan is created in the spring and approved in the third quarter of each year. This aligns with the Enbridge Gas corporate budget cycle and allows sufficient time to procure any required assets to be effective November 1.

69. Any variances from the amounts included in rates and the actual amounts incurred from January 1, 2024, to November 1, 2024, will be addressed through the disposition of the gas supply deferral and variance account balances in the applicable proceedings.

Summary of Gas Costs

Line No.	Particulars ($ millions)	Utility	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Supply									
1	Western Canadian Sedimentary Basin	EGI	207.3	198.4	254.4	276.4	455.0	335.8	525.7	544.5
2	Ontario / Dawn	EGI	540.4	932.7	713.8	357.8	585.9	554.0	704.8	686.9
3	Appalachia	EGI	0.0	81.9	288.8	192.5	364.1	325.7	473.1	487.9
4	Niagara	EGI	278.3	292.2	248.1	194.5	344.9	281.6	432.5	398.2
5	Chicago	EGI	477.1	353.3	172.2	120.4	243.3	295.9	383.7	391.1
6	U.S. Mid-Continent	EGI	49.1	42.0	36.5	37.7	95.0	82.3	117.1	117.5
7	Michigan	EGI	143.0	96.2	0.0	0.0	0.0	0.0	0.0	0.0
8	Gulf Coast	EGI	24.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Third-party Services	EGI	1.0	5.0	8.4	0.2	0.2	0.1	0.0	0.0
10	Unsecured	EGI	0.0	0.0	0.0	0.0	0.0	0.0	0.3	44.8
11	Total Supply Costs - EGI		1,720.9	2,001.7	1,722.2	1,179.5	2,088.2	1,875.4	2,637.3	2,670.8
	Transportation									
12	TCPL Long Haul	EGI	198.6	200.6	184.1	180.3	156.8	157.2	158.8	171.9
13	TCPL Short Haul	EGI	203.3	207.6	139.8	133.2	168.0	174.9	178.1	187.6
14	Nexus	EGI	0.0	20.4	119.5	118.5	116.2	105.4	104.9	105.0
15	Vector	EGI	38.2	28.5	21.7	21.7	21.3	24.8	23.5	23.7
16	U.S. Mid-Continent	EGI	10.6	9.7	10.5	20.5	22.1	22.9	19.4	19.4
17	Nova	EGI	9.3	10.1	12.1	8.1	8.4	7.9	8.2	8.2
18	Great Lakes	EGI	0.0	0.0	1.4	8.0	8.0	6.7	6.5	6.5
19	Centra Pipelines	EGI	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4
20	Michigan	EGI	3.2	3.0	0.0	0.0	0.0	0.0	0.0	0.0
21	Gulf Coast	EGI	2.1	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0
22	Other Transportation	EGI	3.2	3.4	3.2	2.4	3.8	3.6	4.3	3.9
23	Total Transportation Costs - EGI		469.8	484.6	493.6	494.0	505.9	504.7	505.2	527.6

Summary of Gas Costs (Continued)

Line No.	Particulars ($ millions)	Utility	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Other Gas Costs & Adjustments									
24	Gas Deferral Adjustment	EGI	23.4	(296.5)	24.8	26.2	(465.9)	(50.9)	(121.0)	0.0
25	Storage (Injection) / Withdrawal	EGI	117.4	32.3	35.3	89.4	4.8	122.9	53.5	7.4
26	Market-Based Storage (1)	EGI	18.3	19.4	20.1	21.5	21.0	18.2	19.6	13.2
27	Parkway Delivery Commitment Incentive	EGI	15.9	13.0	13.1	13.3	14.1	13.1	14.8	17.6
28	Dawn to Parkway Transportation	EGI	94.5	105.3	116.4	110.2	110.2	118.6	116.9	0.0
29	Transportation Optimization	EGI	2.1	2.8	2.3	1.0	1.7	0.0	0.0	0.0
30	Other Adjustments	EGI	(10.1)	71.8	6.8	13.2	(0.1)	18.1	5.0	0.0
31	Cap and Trade / Federal Carbon	EGI	586.0	371.5	1.3	3.7	5.0	0.0	0.0	0.0
32	Less: Unregulated Costs	EGI	(0.6)	(1.4)	(3.6)	(0.9)	(3.3)	(4.2)	(5.2)	(8.6)
33	Less: Affiliate Adjustment	EGI	(15.6)	(16.8)	(167.0)	(169.9)	(171.2)	(175.8)	(178.9)	0.0
34	Total Gas Costs & Adjustments - EGI		831.4	301.3	49.5	107.8	(483.6)	59.9	(95.2)	29.6
35	Total Utility Cost of Gas	EGI	3,022.1	2,787.7	2,265.3	1,781.3	2,110.6	2,440.1	3,047.3	3,228.0

Note:
(1) 2024 does not include costs associated with incremental 10 PJ related to the ICF recommendation as discussed in Section 2.

2024 Gas Costs to Operations

Line No.	Particulars	Supply (TJ) (a)	Supply (10^3m^3) (b)	Gas Costs ($000s) (c)
	Supply			
1	Western Canadian Sedimentary Basin	118,685	3,036,983	520,433
2	Ontario / Dawn	126,720	3,242,569	667,501
3	Appalachia	100,399	2,569,061	487,894
4	Chicago	71,438	1,827,986	391,116
5	Niagara	80,923	2,070,700	398,241
6	U.S. Mid-Continent	22,011	563,217	117,460
7	Unsecured	7,056	180,546	38,583
8	Total Supply Costs (1)	527,231	13,491,062	2,621,228
	Transportation Costs - System Gas			
10	TCPL Niagara			15,218
11	Nexus			105,008
12	Vector			23,678
13	U.S. Mid-Continent			19,421
14	Nova			8,222
15	Great Lakes			6,528
16	Total Transportation Costs - System Gas			178,075
17	Total Supply and Transportation Costs - System Gas	527,231	13,491,062	2,799,304

Note:

(1) 2024 Total Supply Costs per page 1, column (h), line 11, excluding upstream transportation fuel costs and load balancing and peaking costs per column (c), lines 10 and 12, respectively, ($2,670.8 million - $26.0 million - $23.6 million = $2,621.2 million).

2024 Gas Costs to Operations

Line No.	Particulars	Supply (TJ)	Supply (10^3m^3)	Gas Costs ($000s)
		(a)	(b)	(c)
1	Total Supply and Transportation Costs - System Gas	527,231	13,491,062	2,799,304
2	Storage (Injection) / Withdrawal - System Gas	858	35,580	7,383
3	Total Gas Costs - System Gas	528,089	13,526,642	2,806,687
4	Transportation Costs and Transportation Fuel Costs - Third Party			
5	TCPL Long Haul			171,885
6	TCPL Short Haul			172,350
7	Centra Pipelines			1,407
8	Other Transportation			3,867
10	Upstream Transporation Fuel Costs			26,017
11	Total Transportation Costs and Transportation Fuel Costs - Third Party			375,527
	Other Gas Costs			
12	Load Balancing & Peaking (1)			23,591
14	Market Based Storage Costs (2)			13,246
15	Parkway Delivery Commitment Incentive (PDCI)			17,612
16	Total Other Gas Costs			54,449
	Total Forecasted Gas Costs			3,236,662
17	Less: Unregulated Adjustment			
18	Company Use			224
19	Unaccounted For Gas (UFG)			5,863
20	Compressor Fuel			2,545
21	Total Unregulated Adjustment			8,631
22	Total Utility Forecasted Gas Costs			3,228,031

Notes:
(1) Page 5, line 8.
(2) Amount does not include costs associated with incremental 10 PJ related to the ICF recommendation as discussed in Section 2.

2024 Load Balancing Calculations

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Days in Month	31	29	30	31	31	30	31	31	30	31	30	31	365
2	Supplies (TJ)	20,379	23,600	0	2,012	4,000	13,200	7,686	0	10,823	10,440	10,024	24,150	126,314
3	Average Day Demand Per Month (TJ)	10,699	10,008	10,354	10,699	10,699	10,354	10,699	10,699	10,354	10,699	10,354	10,699	126,314
4	Average Purchases Variance (TJ)	9,680	13,592	(10,354)	(8,687)	(6,699)	2,846	(3,012)	(10,699)	469	(259)	(330)	13,451	0
5	Dawn Forecasted Price ($/GJ)	5.742	5.662	5.234	5.211	5.136	5.098	5.085	5.091	5.047	5.050	5.294	5.551	
6	Price Variance - Load Balancing ($000s) (1)	55,588	76,949	(54,190)	(45,265)	(34,408)	14,511	(15,318)	(54,463)	2,367	(1,306)	(1,745)	74,669	17,390
7	Demand Cost - Load Balancing ($000s)	524	524	524	513	513	513	513	513	513	513	513	524	6,201
8	Total Load Balancing Costs ($000s) (2)	56,112	77,472	(53,666)	(44,751)	(33,894)	15,024	(14,805)	(53,949)	2,881	(793)	(1,232)	75,192	23,591

Notes:
(1) Line 4 x line 5.
(2) Line 6 + line 7.

2024 Comparison of Annual System Gas Supply and Demand

Line No.	Particulars	Supply / Demand (TJ)	Supply / Demand (10^3m^3)
		(a)	(b)
	Supplies To Operations		
1	Supplies (1)	527,231	13,491,062
2	Storage (Injection) / Withdrawal - System Gas (2)	858	35,580
3	Total Supplies	528,089	13,526,642
	Demand Forecast		
4	System Gas (3)	513,276	13,147,613
5	Company Use & Other	774	19,798
6	Unaccounted For Gas (UFG)	11,825	302,578
7	Compressor Fuel	7,510	192,172
8	Customer Supplied Fuel	(5,296)	(135,518)
9	Total System Requirements	528,089	13,526,642

Notes:
(1) Page 4, column (a), line 1.
(2) Page 4, column (a), line 2.
(3) Exhibit 3, Tab 3, Schedule 1, Attachment 8, page 14, column (d), line 36.

Monthly Pricing Information

Line No.	Particulars	21 Day Average Empress CGPR $CAD/GJ	21 Day Average NIT AECO $CAD/GJ	21 Day Average NYMEX $US/MMBtu	21 Day Average Chicago $US/MMBtu	21 Day Average Dawn $US/MMBtu	21 Day Average Dominion South $US/MMBtu	21 Day Average Panhandle Fieldzone $US/MMBtu	21 Day Average Niagara $US/MMBtu	21 Day Average US Exchange $CAD/$USD
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	January 2023	4.9700	4.5367	4.8813	5.4409	4.7590	4.1478	4.8687	4.4615	1.2731
2	February 2023	4.9016	4.4686	4.7221	5.2634	4.6910	4.0358	4.7188	4.3850	1.2733
3	March 2023	4.3837	3.9508	4.2983	4.3353	4.3362	3.6312	4.3882	4.0314	1.2735
4	April 2022	4.5135	4.1029	4.4049	4.2562	4.3229	3.7333	3.9331	4.0248	1.2718
5	May 2022	4.3905	3.9801	4.4225	4.1861	4.2608	3.5814	3.8620	3.9647	1.2719
6	June 2022	4.3750	3.9647	4.4658	4.2052	4.2286	3.6094	3.9218	3.9372	1.2720
7	July 2022	4.4055	3.9954	4.5166	4.2386	4.2177	3.6053	4.0010	3.9166	1.2720
8	August 2022	4.2175	3.8077	4.5253	4.2480	4.2217	3.5066	3.9985	3.9176	1.2722
9	September 2022	4.3011	3.8913	4.5076	4.2037	4.1850	2.7625	3.9734	3.8801	1.2724
10	October 2022	4.4234	4.0138	4.5300	4.2512	4.1864	2.7038	3.9782	3.8857	1.2726
11	November 2022	4.6952	4.2614	4.6185	4.5020	4.3881	3.4554	4.6898	4.0917	1.2729
12	December 2022	4.8917	4.4581	4.7798	4.9759	4.6004	3.8122	4.7973	4.3075	1.2731
13	Average	4.5390	4.1193	4.5560	4.5089	4.3665	3.5487	4.2609	4.0670	1.2726

Notes:
(1) 21 Day Period: January 31, 2022 - February 28, 2022.
(2) MMBtu to GJ conversion rate: 1.055056 GJ/MMBtu.

November 1, 2022 Upstream Transportation Contract Summary

Line No.	Upstream Pipeline / Transportation Service	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Units/d	Contract Expiry	Unitized Demand Charge ($Cdn/GJ)
		(a)	(b)	(c)	(d)	(e)	(f)
	TransCanada Pipeline						
	Long Haul						
1	Empress to Union NCDA FT	Empress	Union NCDA	1,412	GJ	31-Oct-2023	1.147
2	Empress to Union EDA FT	Empress	Union EDA	1,089	GJ	31-Oct-2023	1.347
3	Empress to Union NDA FT	Empress	Union NDA	4,056	GJ	31-Oct-2023	0.899
4	Empress to Union WDA FT	Empress	Union WDA	39,880	GJ	31-Oct-2023	0.580
5	Empress to Union WDA FT	Empress	Union WDA	11,527	GJ	31-Oct-2023	0.580
6	Empress to Union SSMDA FT	Empress	Union SSMDA	2,700	GJ	31-Oct-2023	0.802
7	Empress to Union SSMDA FT	Empress	Union SSMDA	12,800	GJ	31-Oct-2023	0.802
8	Empress to Union SSMDA FT	Empress	Union SSMDA	6,143	GJ	31-Oct-2023	0.802
9	Empress to Union MDA FT	Empress	Union MDA	4,522	GJ	31-Oct-2023	0.416
10	Empress to Union MDA FT	Empress	Union MDA	1,043	GJ	31-Oct-2023	0.416
11	Empress to Union EDA FT	Empress	Union EDA	4,000	GJ	31-Oct-2026	1.347
12	Empress to Union ECDA FT	Empress	Union ECDA	3,000	GJ	31-Oct-2023	1.218
13	Empress to Emerson 2 FT	Empress	Emerson 2	21,418	GJ	31-Oct-2023	0.422
14	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	163,044	GJ	31-Dec-2030	0.930
15	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	70,000	GJ	31-Dec-2030	0.930
16	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	5,000	GJ	31-Dec-2030	0.930
17	Empress to NBJ FT - NBJ LTFP	Empress	North Bay Junction	26,956	GJ	31-Dec-2030	0.930
18	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	163,044	GJ	31-Dec-2030	0.353
19	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	70,000	GJ	31-Dec-2030	0.353
20	NBJ to Enbridge EDA	North Bay Junction	Enbridge EDA	26,956	GJ	31-Dec-2030	0.353
21	NBJ to Enbridge CDA	North Bay Junction	Enbridge CDA	5,000	GJ	31-Dec-2030	0.325
22	Total			643,590	GJ		

November 1, 2022 Upstream Transportation Contract Summary (Continued)

Line No.	Upstream Pipeline / Transportation Service	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Units/d	Contract Expiry	Unitized Demand Charge ($Cdn/GJ)
		(a)	(b)	(c)	(d)	(e)	(f)
	Short Haul						
23	Parkway to Union EDA FT	Parkway	Union EDA	30,000	GJ	31-Oct-2026	0.297
24	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2026	0.297
25	Parkway to Union EDA FT	Parkway	Union EDA	75,000	GJ	31-Oct-2031	0.297
26	Parkway to Union EDA FT (EMB)	Parkway	Union EDA	25,000	GJ	31-Oct-2031	0.326
27	Parkway to Union EDA FT	Parkway	Union EDA	181	GJ	31-Oct-2031	0.297
28	Parkway to Union EDA FT	Parkway	Union EDA	9,105	GJ	31-Oct-2031	0.297
29	Parkway to Union EDA FT	Parkway	Union EDA	5,000	GJ	31-Oct-2032	0.297
30	Parkway to Union EDA FT	Parkway	Union EDA	9,128	GJ	31-Oct-2033	0.297
31	Parkway to Union NCDA FT	Parkway	Union NCDA	661	GJ	31-Oct-2031	0.218
32	Parkway to Union NCDA FT	Parkway	Union NCDA	439	GJ	31-Oct-2031	0.218
33	Parkway to Union NCDA FT	Parkway	Union NCDA	887	GJ	31-Oct-2032	0.218
34	Parkway to Union NCDA FT	Parkway	Union NCDA	2,000	GJ	31-Oct-2032	0.218
35	Parkway to Union NCDA FT	Parkway	Union NCDA	6,912	GJ	31-Oct-2033	0.218
36	Parkway to Union NCDA FT	Parkway	Union NCDA	884	GJ	31-Oct-2033	0.218
37	Parkway to Union NDA FT	Parkway	Union NDA	10,000	GJ	31-Oct-2031	0.454
38	Parkway to Union NDA FT	Parkway	Union NDA	67,000	GJ	31-Oct-2031	0.454
39	Parkway to Union NDA FT	Parkway	Union NDA	24,000	GJ	31-Oct-2031	0.454
40	Parkway to Union NDA FT	Parkway	Union NDA	9,000	GJ	31-Oct-2031	0.454
41	Parkway to Union NDA FT	Parkway	Union NDA	10,401	GJ	31-Oct-2031	0.454
42	Parkway to Union NDA FT	Parkway	Union NDA	6,228	GJ	31-Oct-2031	0.454
43	Dawn to Union CDA FT	Dawn	Union ECDA	8,000	GJ	31-Oct-2023	0.261
44	Niagara to Kirkwall FT	Niagara	Kirkwall	21,101	GJ	31-Oct-2023	0.169
45	Kirkwall to Union CDA FT	Kirkwall	Union CDA	135,000	GJ	31-Oct-2032	0.114
46	Dawn to CDA FT	Union Dawn	Enbridge CDA	4,818	GJ	31-Oct-2026	0.291
47	Dawn to CDA FT	Union Dawn	Enbridge CDA	145,000	GJ	31-Oct-2026	0.291
48	Dawn to EDA FT	Union Dawn	Enbridge EDA	114,000	GJ	31-Oct-2026	0.543
49	Dawn to Iroquois FT	Union Dawn	Iroquois	40,000	GJ	31-Oct-2026	0.522
50	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	572	GJ	31-Oct-2026	0.150

November 1, 2022 Upstream Transportation Contract Summary (Continued)

Line No.	Upstream Pipeline / Transportation Service	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Units/d	Contract Expiry	Unitized Demand Charge ($Cdn/GJ)
		(a)	(b)	(c)	(d)	(e)	(f)
51	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	40,093	GJ	31-Oct-2032	0.150
52	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	75,000	GJ	31-Oct-2034	0.150
53	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	70,000	GJ	31-Oct-2032	0.150
54	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	15,000	GJ	31-Oct-2032	0.150
55	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	8,375	GJ	31-Oct-2032	0.150
56	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	24,484	GJ	31-Oct-2032	0.150
57	Parkway to CDA FT	Union Parkway Belt	Enbridge CDA	100,000	GJ	31-Oct-2036	0.150
58	Parkway to CDA FT-SN	Union Parkway Belt	Victoria Square #2 CDA	85,000	GJ	31-Oct-2026	0.151
59	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	170,000	GJ	31-Oct-2031	0.395
60	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	13,114	GJ	31-Oct-2032	0.395
61	Parkway to EDA FT	Union Parkway Belt	Enbridge EDA	25,000	GJ	31-Oct-2036	0.395
62	Niagara Falls to CDA	Niagara Falls	Enbridge Parkway CDA	76,559	GJ	31-Oct-2030	0.182
63	Chippawa to CDA	Chippawa	Enbridge Parkway CDA	123,441	GJ	31-Oct-2030	0.184
64	Total			1,591,383	GJ		
	Storage and Transportation Service Firm Withdrawal						
65	NCDA	Parkway	Union NCDA	13,704	GJ	31-Oct-2026	
66	WDA	Parkway	Union WDA	31,420	GJ	31-Oct-2026	
67	SSMDA	Dawn	Union SSMDA	35,022	GJ	31-Oct-2026	
68	NDA	Parkway	Union NDA	48,375	GJ	31-Oct-2026	
69	EDA	Parkway	Union EDA	26,351	GJ	31-Oct-2026	0.297
70	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026	0.150
71	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026	0.150
72	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026	0.150
73	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026	0.395
74	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026	0.395
75	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026	0.395
76	Total			519,375	GJ		

November 1, 2022 Upstream Transportation Contract Summary (Continued)

Line No.	Upstream Pipeline / Transportation Service	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Units/d	Contract Expiry	Unitized Demand Charge ($Cdn/GJ)
		(a)	(b)	(c)	(d)	(e)	(f)
	Storage and Transportation Service						
	Firm Injection						
77	WDA	Union WDA	Parkway	3,150	GJ	31-Oct-2026	0.785
78	EDA	Union EDA	Parkway	1,000	GJ	31-Oct-2026	
79	NDA	Union NDA	Parkway	49,100	GJ	31-Oct-2026	0.454
80	CDA	Parkway	Enbridge CDA	153,700	GJ	31-Oct-2026	0.150
81	CDA	Parkway	Enbridge CDA	92,822	GJ	31-Oct-2026	0.150
82	CDA	Parkway	Enbridge CDA	37,370	GJ	31-Oct-2026	0.150
83	EDA	Parkway/Kirkwall	Enbridge EDA	35,089	GJ	31-Oct-2026	0.395
84	EDA	Parkway	Enbridge EDA	35,806	GJ	31-Oct-2026	0.395
85	EDA	Parkway	Enbridge EDA	9,716	GJ	31-Oct-2026	0.395
86	Total			417,753	GJ		
	Centra Transmission Holdings Inc.						
87	Centra Transmission Holdings Inc	Spruce	Union MDA	149.6	10^3m^3	31-Oct-2023	0.475
88	Centra Pipelines Minnesota Inc.	Sprague	Baudette	5,281	MCF	31-Oct-2023	0.126
89	Total			11,627	GJ		
	NOVA Transmission						
90	NIT to Empress	NIT	Empress	50,000	GJ	31-Oct-2024	0.174
91	NIT to Empress	NIT	Empress	75,000	GJ	31-Oct-2025	0.174
92	Total			125,000	GJ		
	Panhandle Eastern Pipe Line Company L.P.						
93	PEPL FT	Panhandle Field Zone	Ojibway (Union)	35,000	DTH	31-Oct-2025	0.819
94	PEPL FT	Panhandle Field Zone	Ojibway (Union)	22,000	DTH	31-Oct-2027	0.819
95	Total			60,138	GJ		

November 1, 2022 Upstream Transportation Contract Summary (Continued)

Line No.	Upstream Pipeline / Transportation Service	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Units/d	Contract Expiry	Unitized Demand Charge ($Cdn/GJ)
		(a)	(b)	(c)	(d)	(e)	(f)
	Vector Pipelines L.P.						
96	Vector US FT1	Chicago	Cdn/US Interconnect	80,000	DTH	31-Oct-2025	0.211
97	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	84,404	GJ	31-Oct-2025	0.006
98	Vector US FT1	Chicago	Cdn/US Interconnect	20,000	DTH	31-Oct-2026	0.211
99	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	21,101	GJ	31-Oct-2026	0.006
100	Vector US FT1	Milford Junction	St. Clair	110,000	DTH	31-Oct-2033	0.187
101	Vector Canada FT1	St. Clair	Dawn	116,056	GJ	31-Oct-2033	0.006
102	Vector US FT1	Alliance	St. Clair	20,000	DTH	31-Oct-2024	0.187
103	Vector US FT1	Northern Border	St. Clair	45,000	DTH	31-Oct-2024	0.211
104	Vector Canada FT1	St. Clair	Dawn	68,579	GJ	31-Oct-2024	0.006
105	Vector US FT1	Chicago	Cdn/US Interconnect	20,000	DTH	31-Oct-2026	0.211
106	Vector Canada FT1	Cdn/US Interconnect	Dawn (Union)	21,101	GJ	31-Oct-2026	0.006
107	Total			622,483	GJ		
	NEXUS Gas Transmission, LLC						
108	NEXUS - FT	Kensington	St. Clair (Union)	150,000	DTH	31-Oct-2033	1.045
109	NEXUS - FT	Kensington	Milford Junction	55,000	DTH	31-Oct-2033	0.963
110	NEXUS - FT	Clarington	Milford Junction	55,000	DTH	31-Oct-2033	1.144
111	Total			274,315	GJ		
	Great Lakes Gas Transmission						
103	GLGT	Emerson	St. Clair	20,000	DTH	31-Oct-2024	0.325
104	Total			21,101	GJ		
	Great Lakes Pipeline Canada Ltd.						
105	Great Lakes Pipeline Canada Ltd.	St. Clair	Union SWDA	21,101	GJ	31-Oct-2024	0.015
106	Total			21,101	GJ		

November 1, 2022 Upstream Transportation Contract Summary (Continued)

Line No.	Upstream Pipeline / Transportation Service	Primary Receipt Point	Primary Delivery Point	Contract Quantity	Units/d	Contract Expiry	Unitized Demand Charge ($Cdn/GJ)
		(a)	(b)	(c)	(d)	(e)	(f)
	St. Clair Pipelines L.P.						
107	St. Clair Pipelines L.P. (St. Clair Pipeline)	St. Clair/Intl Border	St. Clair/Intl Border	214,000	GJ	31-Oct-2023	0.174
108	St. Clair Pipelines L.P. (Bluewater Pipeline)	Bluewater/Intl Border	Bluewater/Intl Border	127,000	GJ	31-Oct-2023	0.174
109	Total			341,000	GJ		
	2193914 Canada Inc.						
110	2193914 Canada Inc.	Vaughan	Lisgar	244,265	GJ	31-Dec-2029	0.022

Notes:
(1) Conversion Factors:
DTH to GJ conversion rate: 1.055056 GJ/DTH
Enbridge North Heat Value: 38.86
Exchange rate: $1 USD = $1.274 CAD

2023 Design Day Position

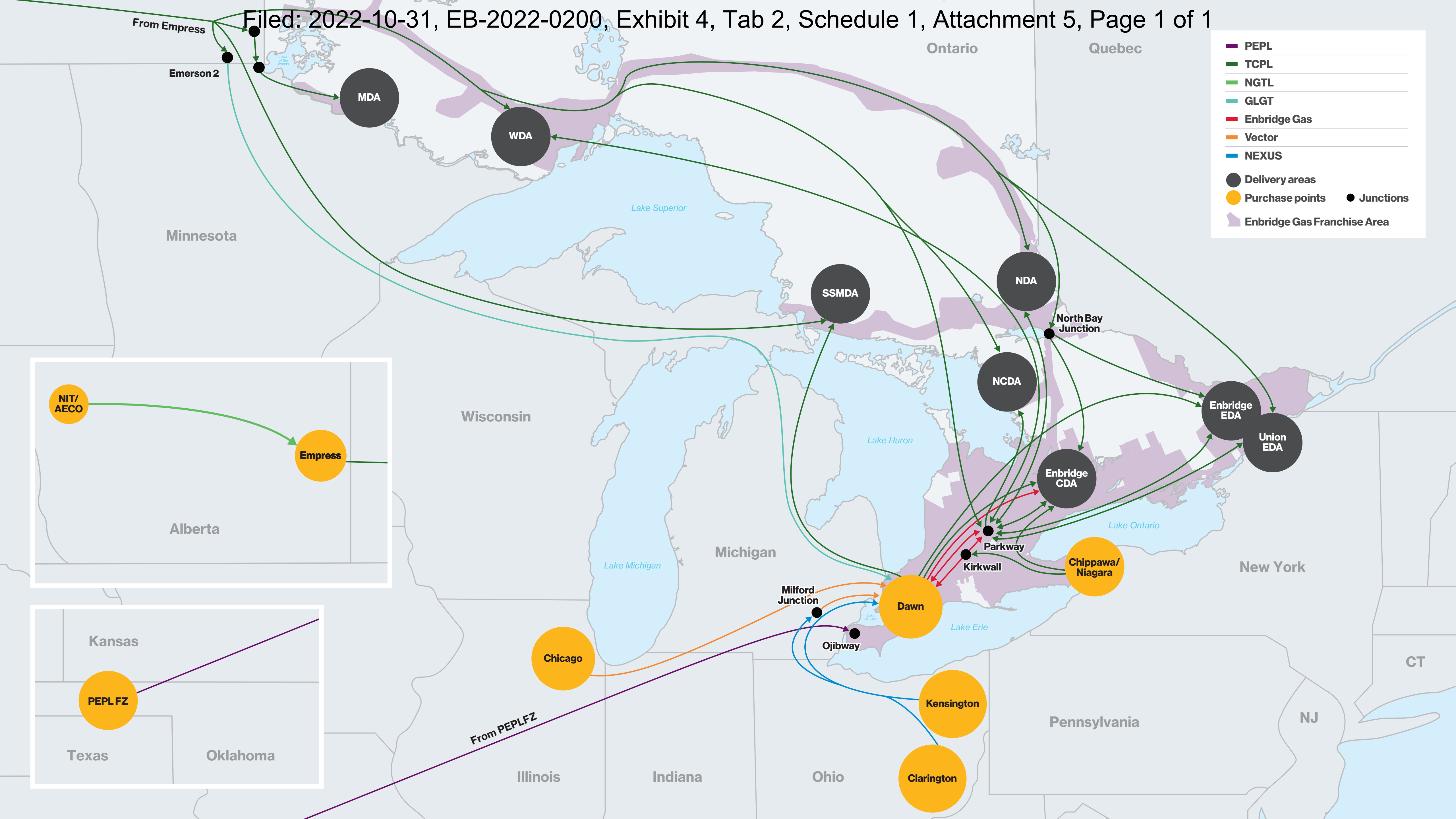
Line No.	Particulars (TJ/d)	Enbridge CDA	Enbridge EDA	Union MDA	Union SSMDA	Union WDA	Union EDA	Union NCDA	Union NDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Design Day Demand	3,360.4	709.5	5.5	41.4	86.2	193.3	43.4	192.8	3,312.1	7,944.6
	Supply										
2	Great Lakes	-	-	-	-	-	-	-	-	21.1	21.1
3	In-franchise Supply (1)	2,263.5	-	-	-	-	-	-	18.1	2,995.8	5,277.3
4	Nexus	-	-	-	-	-	-	-	-	105.5	105.5
5	Panhandle	-	-	-	-	-	-	-	-	60.1	60.1
6	TCPL Long Haul	5.0	260.0	5.6	20.9	51.4	5.0	1.0	2.1	3.0	354.0
7	TCPL Short Haul	768.3	368.1	-	-	-	158.4	11.8	126.6	21.1	1,454.4
8	TCPL STS	283.9	80.6	-	20.5	31.4	26.4	30.6	46.0	-	519.4
9	Vector	-	-	-	-	-	-	-	-	105.5	105.5
10	Unsecured Supply	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
11	Total Supply	3,320.8	708.7	5.6	41.4	82.8	189.8	43.4	192.8	3,312.1	7,897.4
12	Supply Excess / (Shortfall)	(39.6)	(0.8)	0.0	0.0	(3.4)	(3.5)	0.0	0.0	0.0	(47.3)

Note:
(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).

2024 Design Day Position

Line No.	Particulars (TJ/d)	Enbridge CDA	Enbridge EDA	Union MDA	Union SSMDA	Union WDA	Union EDA	Union NCDA	Union NDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Demand										
1	Design Day Demand	3,485.1	697.6	5.6	41.9	88.4	186.8	46.7	182.7	3,327.3	8,062.1
	Supply										
2	Great Lakes	-	-	-	-	-	-	-	-	21.1	21.1
3	In-franchise Supply (1)	2,270.2	-	-	-	-	-	-	8.8	2,752.5	5,031.5
4	Nexus	-	-	-	-	-	-	-	-	158.3	158.3
5	Panhandle	-	-	-	-	-	-	-	-	60.1	60.1
6	TCPL Long Haul	5.0	260.0	5.6	20.9	55.2	5.0	1.0	2.1	3.0	357.8
7	TCPL Short Haul	768.3	368.1	-	-	-	158.4	11.8	126.6	21.1	1,454.4
8	TCPL STS	283.9	80.6	-	21.0	31.4	23.4	33.9	45.2	-	519.4
9	Vector	-	-	-	-	-	-	-	-	311.2	311.2
10	Unsecured Supply	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
11	Total Supply	3,327.5	708.7	5.6	41.9	86.7	186.8	46.7	182.7	3,327.3	7,913.9
12	Supply Excess / (Shortfall)	(157.6)	11.1	(0.0)	0.0	(1.8)	(0.0)	0.0	(0.0)	0.0	(148.2)

Note:
(1) Includes supply arriving directly into the franchise area (i.e. Dawn, storage, DP deliveries, Crowland, Hagar, delivered supply, etc.).


PEPL
TCPL
NGTL
GLGT
Enbridge Gas
Vector
NEXUS
Delivery areas
Purchase points
Junctions
Enbridge Gas Franchise Area
From Empress
Emerson 2
MDA
WDA
SSMDA
NDA
NCDA
North Bay Junction
Enbridge EDA
Union EDA
Enbridge CDA
Parkway
Kirkwall
Chippawa/ Niagara
Dawn
Milford Junction
Ojibway
Chicago
Kensington
Clarington
From PEPLFZ
NIT/ AECO
Empress
Alberta
Kansas
PEPL FZ
Texas
Oklahoma
Ontario
Quebec
Minnesota
Wisconsin
Michigan
New York
Pennsylvania
Illinois
Indiana
Ohio
NJ
CT
Lake Superior
Lake Huron
Lake Michigan
Lake Ontario
Lake Erie

Assessment of Storage Capacity Requirements for Enbridge Gas In-franchise Bundled Service Customers

October 12 , 2022

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Contents

1 Introduction and Summary

1.1 Purpose

As part of the 2024 Rebasing Application (referred to as the Application), designed to set rates as of January 1, 2024, Enbridge Gas Inc. (referred to as Enbridge Gas) is proposing to integrate the storage planning process as a result of the amalgamation of Enbridge Gas Distribution (EGD) and Union Gas Limited (Union) on January 1, 2019.

Enbridge Gas also agreed to provide more information on storage costs and market-based alternatives to the purchase of third-party storage in its supply portfolio as part of this application:

> "In connection with the settlement of this item, Enbridge Gas has agreed to file evidence in its rebasing application (for rates as of January 1, 2024, which will include requests for approvals for the pass-through of gas supply costs) demonstrating that it has fully considered the opportunity to reduce storage costs through inclusion, as part of its load balancing portfolio, of cost-effective market-based alternatives to the purchase of third-party storage. That evidence will include consideration of: (i) the cost of delivered supply (including the commodity cost) in winter in lieu of contracting for additional storage: versus (ii) the cost (savings) of buying gas in summer and the associated additional storage and related costs required to store and redeliver that gas in the winter."[1]

Enbridge Gas retained ICF to assess the appropriate mix of winter supply purchases as compared to holding storage assets for meeting Enbridge Gas's load balancing needs for bundled service customers. As part of this engagement, Enbridge Gas informed ICF that the Application reflects 218 PJ of storage services to serve in-franchise customers. This includes 203[2] PJ of storage services to serve the utility's bundled in-franchise customer gas supply requirements and 15 PJ of capacity for T-Service customers. Enbridge requested that ICF evaluate the proposed level of storage services and make recommendations on whether Enbridge should change the level of storage capacity.

This report documents ICF's recommendations on the level of contracted storage capacity that would be optimal for Enbridge Gas and provide an assessment of the determination of Enbridge Gas' natural gas storage requirements relative to other market-based alternatives for bundled service customers.

1.2 Structure of Report

This report documents the results of ICF's market analysis and storage value analysis and provides an assessment of the current Enbridge Gas methodology of determining storage requirements and whether there is benefit to modifying this approach. The remainder of **Section 1** provides an overview of the analysis and a summary of results. **Section 2** of this report provides an overview of the key market trends expected to determine storage value and utilization in the future. **Section 3** of this report provides a broad overview of the alternatives to market-based storage capacity. **Section 4** documents the approach used in the storage analysis and provides results of ICF's analysis and recommendations for Enbridge Gas future storage capacity. ICF's conclusions and recommendations are presented in **Section 5** of the report.

[1] Footnote o/s
[2] The 203 PJ of storage capacity for bundled service customers includes 185 PJ of utility owned storage near the Dawn Hub provided at the cost of service, and 18 PJ of physical and synthetic storage services contracted from third parties at market-based rates near the Dawn Hub

1.3 Overview of Approach

The ICF assessment of the value of storage capacity for Enbridge Gas in-franchise customers is based on a combination of different analytical methodologies for assessing natural gas markets.

- ICF used the Enbridge Gas forecast of natural gas demand for the 2023-2028 time-period throughout the analysis.[3]
- ICF used its April 2022 Gas Market Model (GMM) as the starting basis for its evaluation of the North American natural gas markets and Enbridge Gas' gas storage operations. The GMM is an internationally recognized model of the North American gas market that includes projections for natural gas demand by sector, conventional and unconventional natural gas resources, production costs, and other major gas market developments, such as potential Liquefied Natural Gas (LNG) exports. The GMM projects monthly natural gas demand, supply, and prices for more than 120 regions and is a general equilibrium market model. The model is described in more detail in Appendix C. ICF used the GMM to conduct analysis of the potential impacts and risks associated with alternative weather scenarios on natural gas demand and prices.
- ICF developed a series of alternative weather scenarios to assess the impact of different weather patterns on storage value. These weather scenarios were based on real weather patterns over a five-year period.
- ICF requested that Enbridge Gas perform a set of portfolio analysis optimization scenarios to assess the value of storage capacity under different gas price and weather scenarios. Enbridge Gas used their gas supply planning model (Supply Planning Model)[4] to conduct this analysis. The analysis uses a base gas supply portfolio which represents the bundled demand and assets that EGI determined to be consistent with the use of Aggregate Excess to determine storage capacity. The Enbridge Gas analysis is underpinned by EGI's demand forecast, and Enbridge Gas' upstream contract costs at the time of developing the Application.

  We also tested each weather scenario using a lower storage capacity gas supply scenario developed with 5 PJ less storage than indicated by the Aggregate Excess methodology to evaluate the impacts of replacing storage capacity with winter purchases at Dawn on supply portfolio costs.

  We then tested each weather scenario to determine the impact of increasing storage capacity and reducing the reliance on winter purchases at Dawn using two different approaches to test different levels of storage capacity. EGI modeled three 10 PJ tranches of incremental market-based storage and included them in the Aggregate Excess portfolio. EGI assumed each 10 PJ tranche was 5% more expensive than EGI's most recent market-based storage contract and assumed the contracting parameters similar to existing physical storage services contracted by Enbridge Gas in recent years, with 1.2% maximum deliverability and 0.75% maximum injectability.

  Once the incremental storage tranches were included in the Aggregate Excess portfolio, EGI ran Supply Planning Model using the Application's Resource Mix optimization function for each commodity price forecast provided by ICF. With SENDOUT© optimizing using the Resource Mix function and assuming each of the ICF commodity price forecasts, the gas supply planning model was able to determine what

[3] ICF did not assess the impact of changes in Enbridge Gas in-franchise customer demand on the value of storage. Increases or decreases in demand due to local weather or due to changes in customer demand trends would lead to changes in the value of storage.
[4] The Enbridge Gas Supply Planning Model is based on the SENDOUT© gas dispatch optimization framework.

level of incremental storage, if any, provided a lower cost portfolio than the Aggregate Excess portfolio.

We then asked Enbridge to fix the level of incremental storage capacity at different levels for one weather scenario to confirm the results of the optimization analysis.

- ICF used the results of the analysis to assess the value of increasing or decreasing natural gas storage capacity relative to the levels currently held by Enbridge Gas for bundled in-franchise customers.

Assessment of Enbridge Gas Aggregate Excess Methodology

Historically, Enbridge Gas has used an aggregate excess approach to determining storage requirements, with minor differences[5] between the methodology used by EGD and Union service territories. According to the OEB, "The aggregate excess method is the difference between the amount of gas a customer is expected to use in the 151-day winter period and the amount that would be consumed in that period based on the customer's average daily consumption over the entire year."[6] The aggregate excess methodology provides an estimate of the amount of storage capacity needed to optimize the utilization of contracted pipeline assets and minimize the uncertainty associated with meeting natural gas demand under normal weather conditions.

In and of itself, the aggregate excess methodology does not determine the optimal amount of storage capacity needed to minimize long term supply costs.

- In a market with significant excess pipeline capacity or other sources of winter gas supply being available at costs that are lower than the cost of meeting winter demand with storage, the aggregate excess methodology could result in a higher cost supply portfolio than holding a lesser amount of storage.
- However, in a market where prices and demand are more volatile than the normal conditions used to assess the amount of aggregate excess, and where there is limited available winter pipeline capacity or supply, or the available supply is higher cost than storage, the aggregate excess methodology will underestimate the amount of storage that should be held in an optimal supply portfolio.

In addition, the Aggregate Excess methodology is designed around normal weather. During some years, total supply costs might be lower if storage levels below the level indicated by aggregate excess are included in the portfolio, and in other years, the supply costs might be lower if storage levels above the aggregate excess are included in the portfolio.

The calculation of Aggregate Excess is based on a demand forecast reflecting normal weather. Standard variation in weather will lead to different valuations of the aggregate excess storage capacity. During some years, total supply costs might be lower if storage levels below the aggregate excess are included in the portfolio, and in other years, the supply costs might be lower if storage levels above the aggregate excess are included in the portfolio.

The expected seasonal swings in prices, combined with the limited availability of incremental pipeline capacity

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[5] The Aggregate Excess methodologies used by legacy EGD and legacy Union Gas differed slightly based on the inclusion of own-use demand in the legacy Union Gas methodology and exclusion of own-use demand in the legacy EGD methodology. As the starting point for the Rebasing Application, Enbridge Gas used the legacy EGD methodology, which results in a lower level of indicated natural gas storage. The legacy Union Gas approach would have indicated an Aggregate Excess level of 208 PJ of storage capacity rather than 203 PJ.

[6] Ontario Energy Board, "Motions to Review the Natural Gas Electricity Interface Review Decision – Decision with Reasons" May 22, 2007. Page 59.

and the availability of storage capacity in the market region support the contracting for incremental market-based storage capacity up to the level indicated by the aggregate excess methodology. For the purpose of evaluating the optimal level of storage and to provide an assessment of market-based alternatives, ICF asked Enbridge Gas to provide a gas supply planning model run for the base case where additional market-based storage capacity was available as part of the solution. Under normal weather conditions, the Enbridge Gas's Supply Planning Model selected incremental storage capacity in the solution in one out of the five years evaluated. The reduction in supply costs during this one year more than offset the increase in cost of holding the incremental market-based storage capacity for the full five-year period, supporting the hypothesis that the Aggregate Excess methodology generally understates the optimal amount of storage capacity that should be included in the long-term Enbridge Gas supply portfolio.

Development of Alternative Weather Scenarios

The Aggregate Excess methodology does not address the value of natural gas storage with respect to system reliability and resiliency, or to protect against unpredictable supply pricing events resulting from volatile weather and pricing conditions that occur during real world weather and pricing conditions. This is consistent with most natural gas supply planning approaches. Most natural gas supply planning is based on "normal" weather conditions, with accommodations to account for design day or peak day demands that typically would occur due to extremes in weather conditions and with accommodations for colder than normal winters.

However, in the near term, changes in North American weather patterns are an important driver of storage value. The impact on value is seen both in the role that natural gas storage plays in optimizing natural gas supply portfolio costs, as well as in the market price for storage.

The ICF Base Case forecast of natural gas prices is based on a "normal" weather pattern based on 20-year average HDD patterns. The use of normal weather allows for a consistent forecast based on the same season weather pattern every year. As a result, the normal weather forecast identified the impact of other expected changes in natural gas markets, including the impact of supply and demand trends, but does not capture the impact of changes in weather. In addition, the use of a normal weather forecast leads to a dampening of the typical year-to-year differences in natural gas markets and market prices caused by the difference between actual weather patterns which vary widely from year to year, and "normal" weather. Actual weather conditions fluctuate more on a monthly basis than normal weather, which has the same seasonal pattern every year and which is created as an average of many years of actual data. As a result, use of normal weather tends to underestimate the value of natural gas storage in a utility supply plan.

The use of normal weather in the planning process ignores the impact of year-to-year market price and demand volatility in gas markets. In addition, since the normal weather assumptions are based on a 20-year average data, normal weather does not capture any extreme weather events which tend to increase or decrease demand and in turn cause rapid price swings. Much of the value of natural gas storage capacity is captured during a limited number of years when weather is colder than normal or when natural gas market conditions result in significant price increases and constraints on natural gas market availability.

To assess the value of natural gas storage for Enbridge Gas under different weather scenarios, ICF used the GMM to develop four alternative price scenarios reflecting different weather patterns (Normal weather, Warmer than Normal Weather, Typical Weather and Colder than Normal Weather).[7] The first scenario is based on

[7] The ICF Weather Scenarios used actual North American weather data to project natural gas prices at different market centers under different weather patterns. We used the base case Enbridge Gas demand forecast throughout the rest of analysis.

normal weather reflecting average weather patterns over a 20-year period from 2002 to 2021. This is consistent with the Enbridge Gas weather normal assumptions. The other three scenarios were based on actual five years of weather data rather than an average of weather over multiple years:

1) The Warmer than Normal Weather scenario is based on the actual monthly HDD data for the warmest 5-year period between 1980 and 2020. This was 2015 - 2019.

2) The Typical Weather scenario is based on actual monthly HDD data for the 5-year period that most closely matched the HDD data in the Normal Weather scenario. This was 2008 – 2012.

3) The Colder than Normal Weather scenario is based on the actual monthly HDD data for the coldest 5-year period between 1980 and 2020. This was 1981 - 1985.

The use of actual weather scenarios is an important consideration to allow for a more complete assessment of the actual range of impacts due to the range of positive and negative correlations between the weather patterns of different regions across North America.

The four different weather scenarios lead to significant changes in natural gas commodity prices, including both the absolute prices and the month to month and year to year price volatility. All three of the alternative weather scenarios that are based on actual weather patterns exhibited greater price volatility than the normal weather case, leading to additional value for natural gas storage. The resulting commodity prices across the four weather cases (shown in Exhibit 4-3) were used by Enbridge Gas to assess the impact of alternative storage scenarios on Enbridge Gas' natural gas supply portfolio costs using the Enbridge Gas Supply Planning model.

1.4 Analysis of Storage Value

The evaluation of the value of natural gas storage in the Enbridge Gas' bundled customer supply portfolio started from the storage capacity requirements proposed by Enbridge Gas in the rebasing application, consistent with the level of storage indicated by the Aggregate Excess methodology. Based on the Enbridge forecast of demand, Enbridge Gas would need to continue to maintain the current 203 PJ of cost of service and market-based storage capacity, increasing to 208 PJ of storage capacity by 2027/28 to provide the service underpinning the Aggregate Excess methodology.

In order to evaluate the potential costs and benefits of diverging away from the Aggregate Excess methodology, ICF performed three sets of analysis:

1) **Reduced Storage Capacity Analysis** –ICF evaluated a supply plan based on a minimum storage capacity 5 PJ lower than the level suggested by the Aggregate Excess methodology. The purpose of this analysis is to evaluate the impact on total portfolio costs of holding less storage than the amount identified using the Aggregate Excess methodology. The results of this analysis suggest that incremental storage capacity should also be considered.

2) **Resource Mix Optimization Analysis** – ICF used the results of the Enbridge Gas's gas supply planning model analysis to evaluate the impact of changes in storage capacity for the Base (or Normal Weather) case and for each of the three alternative weather scenarios to determine the potential costs and benefits of changing the amount of storage capacity used by Enbridge Gas relative to the currently contracted level of storage capacity. The purpose of this analysis is to determine the range of incremental storage the Enbridge Gas Supply Planning model would select under different weather scenario price forecasts, in order for ICF to determine a fixed level of storage to evaluate.

3) **Fixed Storage Capacity Analysis** – In the Resource Mix Optimization Analysis, the Enbridge Supply Model selected the optimum storage capacity in each year and operated the storage system according to the amount of storage selected. This analysis suggested that incremental storage capacity would provide value to Enbridge in-franchise bundled service customers. In order to validate the results of this analysis, ICF also requested that Enbridge Gas run their Supply Planning Model analysis with fixed amounts of incremental storage capacity over the 5-year planning period. The 5 PJ, 8 PJ, 10 PJ and 20 PJ amounts evaluated in this analysis were selected by ICF to approximate the range of incremental capacity identified in the Resource Mix Optimization analysis.

   ICF based the Fixed Storage Capacity Analysis on the typical weather scenario rather than the Normal Weather scenario since the typical weather case is a better representation of how weather conditions impact price and weather volatility. Given the results of the Resource Mix Optimization analysis, it was clear that additional storage would provide additional benefits in the warm and cold weather scenarios, hence the additional analysis would not have provided sufficient value to justify the level of effort required.

The results of the three sets of analysis are summarized below.

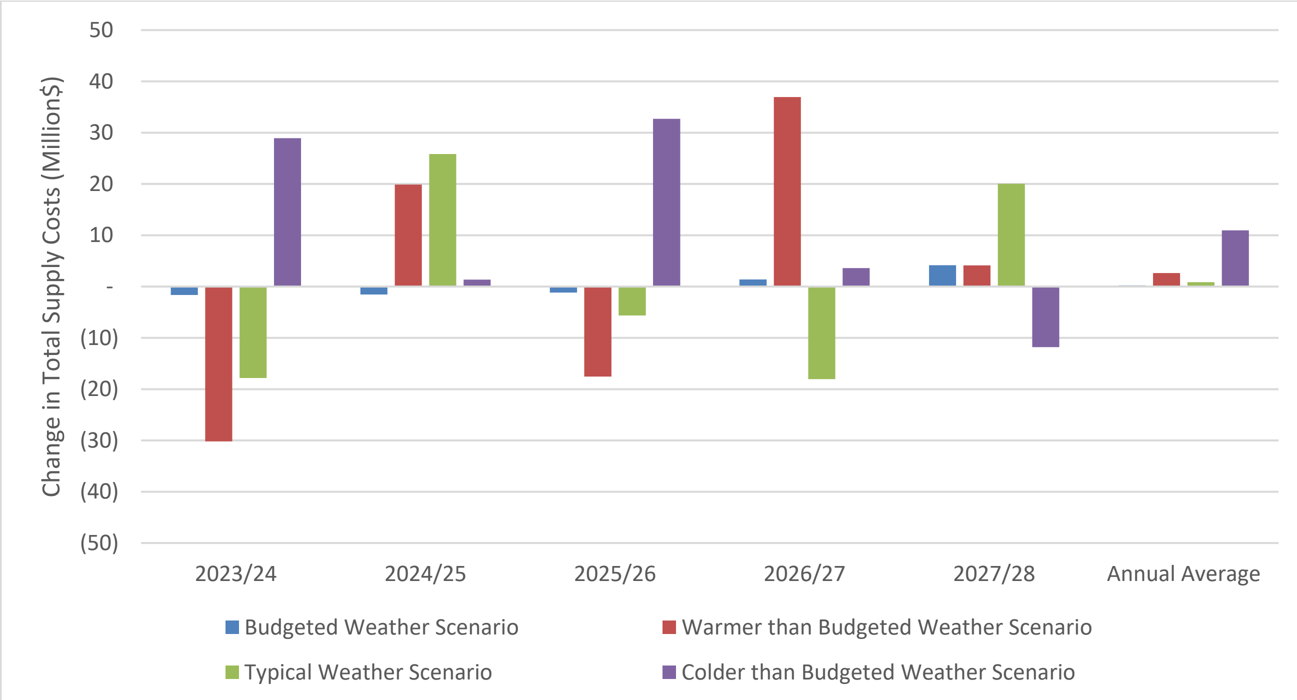
<u>Reduced Storage Capacity Analysis</u>

As outlined in Section 3, Enbridge Gas asked ICF to address whether there were viable market-based alternatives to the market-based storage capacity, and whether these alternatives would allow Enbridge Gas to hold less market-based storage capacity to serve bundled service customers. ICF considered two broad alternatives to the use of market-based storage capacity in the bundled service customer supply portfolio; 1) the potential to hold additional pipeline capacity to serve the load served by the market-based storage; and 2) the substitution of incremental purchases at Dawn for winter storage withdrawals, combined with winter peaking service to offset the storage contributions to design day.

As explained in Section 3, incremental pipeline capacity is not likely to be available or would require additional capacity on upstream pipelines to provide reliable winter service to Dawn and would not be a cost-effective alternative. However, incremental purchases at Dawn would be a potentially viable alternative to holding storage capacity.

In order to assess the impact on the supply portfolio of reducing storage capacity, Enbridge Gas ran the Supply Model with a 5 PJ decrement relative to the amount of storage capacity indicated by the Aggregate Excess methodology for each of the four weather scenarios. The results of the analysis indicate that reducing storage capacity below the level indicated by the Aggregate Excess methodology can result in small reductions in the portfolio costs depending on the weather scenario selected when calculated by the supply planning model, but the reduction in portfolio costs would be more than offset by the costs associated with offsetting the reduction in storage deliverability for design day planning and for system reliability and resiliency. Exhibit 1-1 is a summary of the change in total portfolio costs when reducing the storage portfolio by 5 PJ:

Exhibit 1-1 : Summary of Impact of Reduced Storage Capacity on Portfolio Cost



Resource Mix Optimization Analysis

The results of the analysis of the reduction in storage capacity suggested that an increase in storage capacity above the level indicated by the Aggregate Excess methodology should also be considered. In order to assess the potential value of incremental storage capacity, ICF requested that Enbridge Gas run the Gas Supply model allowing the model to select the optimum amount of storage capacity for each of the weather scenarios considered.

The results of the resource mix optimization analysis indicated when additional storage capacity was made available the analysis of the different weather options resulted in different levels of storage capacity to optimize the cost of the Enbridge Gas supply portfolio in different years. As shown in Exhibit 1-2, in some years no additional storage capacity was utilized in the optimized supply dispatch, while in other years, up to 30 PJ of additional market-based storage capacity was utilized to optimize the supply portfolio.[8] More storage was picked up in the warm and cold weather cases compared to the normal weather case due to higher seasonal demand seen across these cases.

[8] The analysis did not consider the addition of more than 30 PJ of incremental storage capacity.

Exhibit 1-2 : Optimized Storage Capacity for Enbridge Gas In-Franchise Bundled Services Customers

	Optimized Storage Capacity (PJ)				
	2023/24	2024/25	2025/26	2026/27	2027/28
Aggregate Excess Storage Capacity					
Normal Weather Case	203	203	203	203	203
Warm Weather Case	203	203	203	203	203
Typical Weather Case	203	203	203	203	203
Cold Weather Case	203	203	203	203	203
Incremental Storage Capacity					
Normal Weather Case	0.0	0.0	0.0	0.0	10.5
Warm Weather Case	0.0	0.0	25.9	30.0	3.4
Typical Weather Case	0.0	19.1	0.0	0.0	25.3
Cold Weather Case	3.2	0.0	30.0	0.0	12.5
Total Optimized Storage Capacity					
Normal Weather Case	203	203	203	203	213
Warm Weather Case	203	203	229	233	206
Typical Weather Case	203	223	203	203	229
Cold Weather Case	206	203	233	203	215

As illustrated in Exhibit 1-2, the Normal weather case required additional storage capacity in one year out of the five-year period evaluated, the Typical Weather Case was optimized with additional storage in two out of five years, and the warm weather and cold weather cases were optimized with additional storage capacity in three out of the five years.

These results would imply that the optimal amount of storage capacity held in the Enbridge Gas supply portfolio should vary from year to year between 203 PJ and 233 PJ based on weather and market conditions. However, the storage market does not operate in a world with perfect foresight into weather and gas market conditions. In addition, market-based storage capacity cannot efficiently be contracted and de-contracted on a year-by-year basis.[9]

Instead, the amount of storage capacity included in the utility's annual supply portfolio must be determined without knowing future weather conditions, and with limited insight into changes in natural gas market conditions. In a supply portfolio optimized without perfect foresight, we would anticipate that the amount of storage capacity included in the supply portfolio would be relatively stable from year to year, responding to changes in natural gas demand forecasts and changes in natural gas market conditions, but not changing based on year-to-year changes in weather.

This approach will lead to years where the utility could have reduced supply costs by holding additional storage capacity, and other years where the utility could have reduced supply costs by holding less storage capacity. To assess the optimal amount of storage for the Enbridge Gas supply portfolio, ICF evaluated the balance between the cost savings associated with holding additional storage capacity in the years where the additional storage

[9] A certain amount of incremental storage capacity likely would be available on an annual basis. However, the cost of the incremental storage would fluctuate with the market, and likely would be highest during periods when prices are increasing, and when the storage would provide the most potential value to the utility.

capacity provided incremental value to the costs of holding additional storage capacity in the years where the additional storage capacity was not needed.

The overall change in total gas costs for the five-year period from April 2023 through March 2028 for each of the weather scenarios are shown in Exhibit 1-3[10].

Exhibit 1-3 : Average Annual Change in Total Gas Costs from Incremental Storage Capacity from Enbridge Gas SENDOUT© Results

Average Annual Impact of Incremental Storage Capacity on Enbridge Gas Supply Portfolio Costs for the Five-Year Period from April 2023 to March 2028 *(CAD$Millions)*	
Normal Weather Scenario	(0.4)
Warm Weather Scenario	(7.3)
Typical Weather Scenario	(4.9)
Cold Weather Scenario	(33.6)

**Negative costs imply a reduction in total cost

ICF's analysis indicates that over the five-year period evaluated, the value of holding incremental storage capacity in the years when it was useful more than offset the cost of holding the same storage capacity in the years where the storage capacity was not useful. In the Normal Weather Case, adding an additional 11 PJ of storage capacity above the currently committed levels would lead to a reduction in overall supply costs of C$438,000 per year. In the Typical Weather Scenario, adding an additional 25 PJ of storage capacity above the currently committed levels would lead to a reduction in overall supply costs of C$4.97 million per year.

In both the Warm Weather Case and the Cold Weather case, the analysis indicated that adding 30 PJ of storage capacity would be economic over the five-year period. In the Warm Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$7.3 million per year, while in the Cold Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$33.6 million per year.

As a result of the outcome and incremental storage amounts identified in Exhibit 1-2, ICF used this to determine a range of incremental storage levels to evaluate, holding these amounts constant over the 5-year period, which more closely replicates how a utility would contract for storage capacity.

Fixed Storage Capacity Analysis

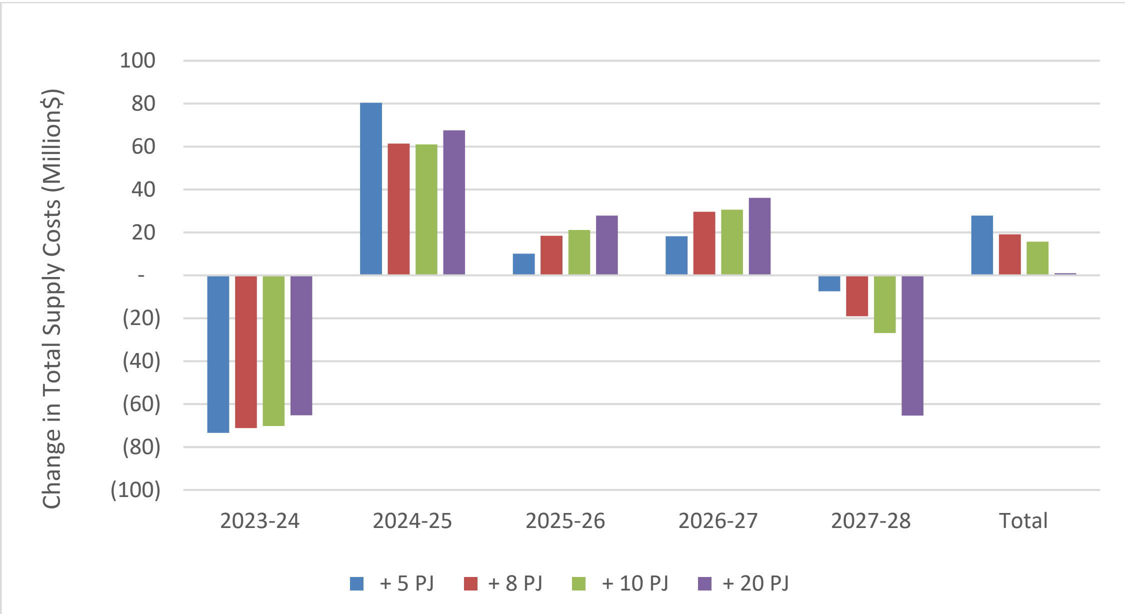
In order to confirm the results of the optimization analysis of storage capacity, ICF also evaluated the impact of different levels of storage capacity on supply portfolio costs for the Typical Weather scenario to assess the impact on supply portfolio costs. This was done to assess total portfolio cost impacts based on holding different levels of incremental storage capacity constant over the 5-year period. The results of the analysis are shown below.

As indicated in Exhibit 1-4, in the Typical Weather scenario, additional storage capacity reduced overall costs in 2023/24 and in 2027/28, but resulted in an increase in costs in 2024/25, 2025/26, and 2026/27. Over the 5-year period, total costs were relatively flat across the range of incremental storage capacity. As outlined in Exhibit

[10] The costs in Exhibit 1-3 reflect the incremental storage capacities outlined in Exhibit 1-2

4-13, costs changed between 0.008% and 0.2% relative to the total supply portfolio cost depending on the amount of incremental storage capacity. This is in line with expectations given the price of storage capacity used in the analysis reflects actual storage contracts signed in the recent past, where we would anticipate that the storage cost reflects the value associated with the storage capacity.

Exhibit 1-4 : Impact of incremental storage capacity on Total Supply Portfolio Costs (Million$) in the Typical weather cases



1.5 Recommendations and Conclusions

Enbridge Gas estimated an aggregate excess storage capacity for bundled service customers of 203 PJ for the 2023-24 storage year. This value increases to 208 PJ by the 2027/28 storage year based on projected natural gas demand growth within this customer group. Given 185 PJ of utility owned storage capacity valued at the cost of service, this would require 18 PJ of market-based storage in 2023/24, increasing to 23 PJ of market-based storage in 2027/28.

Based on our assessment of storage economics and the value of storage in reducing customer cost volatility, ICF would consider the estimate of the Aggregate Excess to represent a lower bound on the appropriate level of storage capacity needed to serve in-franchise bundled service customers rather than the optimal amount. The analysis of a lower storage capacity scenario indicates that the reduction in storage costs would be more than offset by increases in non-storage supply costs and the reduction in value resulting from the decrease in storage deliverability.

ICF's assessment of storage value under different weather conditions and time periods suggests that Enbridge Gas should hold a certain amount of additional market-based storage capacity above the level indicated by the Aggregate Excess methodology to meet design day system capacity requirements, to increase system reliability and reduce cost volatility to Enbridge Gas customers, and potentially to reduce overall costs to Enbridge Gas customers.

ICF's analysis indicates that the direct costs of holding incremental storage capacity are likely to be roughly offset by reductions in gas supply costs over a fairly broad range of incremental storage capacity. In the typical weather scenario, the direct benefits (reductions in supply costs) provided by storage continue to improve as additional storage is added to the portfolio up to the maximum level of incremental capacity (20 PJ) evaluated by ICF. However, the incremental benefits are modest and could be offset by increases in the cost of incremental storage capacity. As a result, the overall amount of incremental capacity that should be considered by Enbridge Gas will depend on the cost of the incremental storage at the time that Enbridge Gas goes into the market to acquire the storage, and the level of importance Enbridge Gas, the OEB, and other stakeholders place on maximizing supply reliability and minimizing cost volatility vs. the risk of holding excess storage capacity in years where the additional storage capacity does not provide incremental value.

ICF's analysis suggests that Enbridge Gas should consider increasing the amount of market-based storage capacity held for bundled service customers by about 10 PJ from 18 PJ to 28 PJ. This recommendation reflects a balance between cost, cost volatility, design day reliability, and minimizing up front contract cost commitments for supply services and reflects the results of the assessment of the value of storage under different weather conditions, and the assessment of the impacts of different levels of storage capacity on costs for the typical weather scenario. The recommendation is based on both the analysis of alternative weather scenarios, and the analysis of alternative storage capacity levels for the "Typical Weather" scenario.

2 Implications of Changes in Natural Gas Markets on Storage Value

ICF is forecasting significant changes in the value of natural gas storage over the next five years, with lower seasonal value during the next two to three years as natural gas prices generally decline from current high prices, followed by a significant increase in seasonal values after 2025. This section of the report reviews the changes in natural gas market conditions that ICF expects to impact the natural gas markets and the value of gas storage for Enbridge Gas. The first section presents an overview of ICF's North American natural gas market outlook. The second section is focused on the Canadian gas market, examining the potential shifts in inter-regional pipeline flows and natural gas prices. The third section looks at the impact of weather on natural gas storage scenarios and how ICF constructed its weather cases that Enbridge Gas used to evaluate various gas storage options.[11]

2.1 North America Gas Market Outlook

North American Demand Outlook

The ongoing Russia-Ukraine conflict as well as the rebound in market activities post covid pandemic are leading to continued growth in gas consumption and exports from North America. Through 2025, growth in North America demand is primarily export driven, and most of the expected exports are via LNG terminals and piped gas to Mexico. Natural Gas demand trends in Canada are expected to closely follow the rest of North America.

The power generation sector has also been a major driver of incremental gas consumption within North America. Even though prices of natural gas are currently higher than coal, we are seeing very limited gas to coal switching. Gas to coal switching has been limited due to relatively low coal stockpiles. Utilities appear to be limiting coal consumption to limit the drawdown on stocks due to potential shortages and delays in future coal deliveries. In addition, much of the coal capacity has retired in the past decade due to environmental regulations favoring natural gas-fired plants, which has reduced the potential to switch to coal during periods of high natural gas prices. There has also been increased coal demand from Western Europe as it has discontinued Russian supplies. As a result, power producers are using more natural gas rather than coal, leading to growth in power sector gas consumption.

As the economy has recovered from the pandemic shocks, gas consumption in the industrial sector has also increased given the uptick in the petrochemical and manufacturing sectors which are concentrated on the U.S. Gulf Coast. Industrial demand is projected to increase by about 9 percent by 2025 from the lows seen in 2021. Lately, markets are seeing a slacking demand growth due to an anticipated economic slowdown given the consistent high price environment

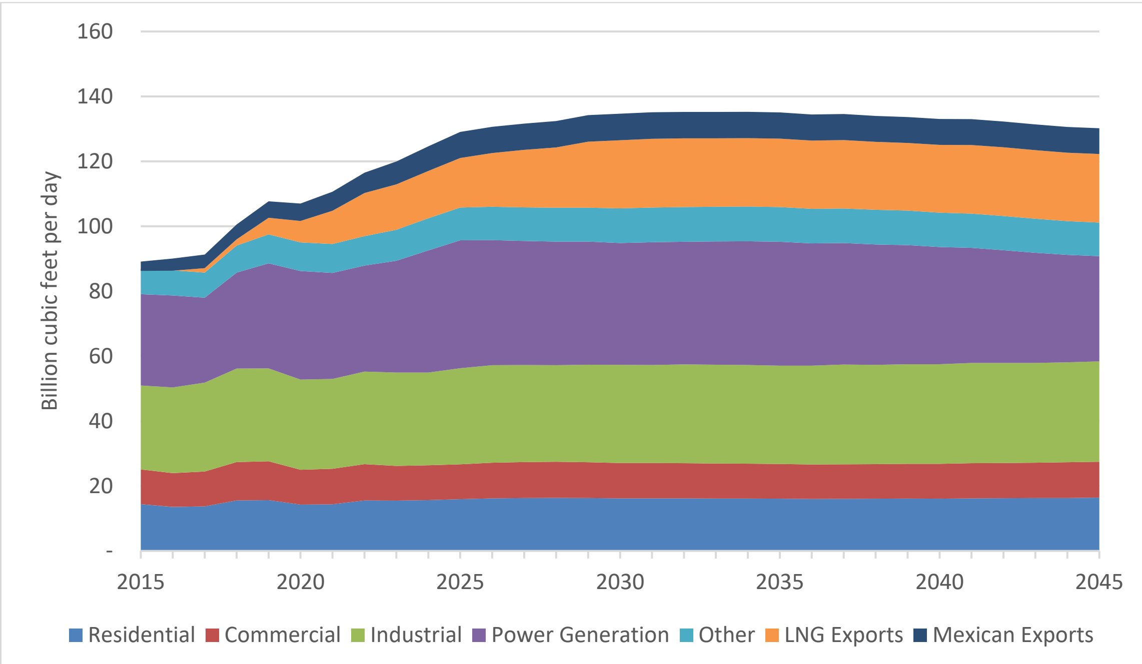
Residential and commercial gas demands are expected to rise only slightly, as increased demand due to the addition of new gas customers is partially offset by reductions in per-customer consumption due to energy efficiency improvements.

ICF's base case model includes carbon price assumptions reflecting known and anticipated North American carbon policy. ICF assumes charges on $CO2$ emissions from the power sector for California and the RGGI states escalate throughout the forecast. Charges in other states (collectively) begin as early as 2022.

[11] The outlook and forecasts discussed in this section are those of ICF and may differ from views of Enbridge Gas in some respects.

Gas demand in Mexico is expected to increase sharply to meet growing power generation gas demand in Mexico. By 2025, ICF projects that pipeline export to Mexico will reach 8 Bcfd, 38% above the export volumes in 2021.

Exhibit 2-1 : US and Canada Natural Gas Demand by Sector

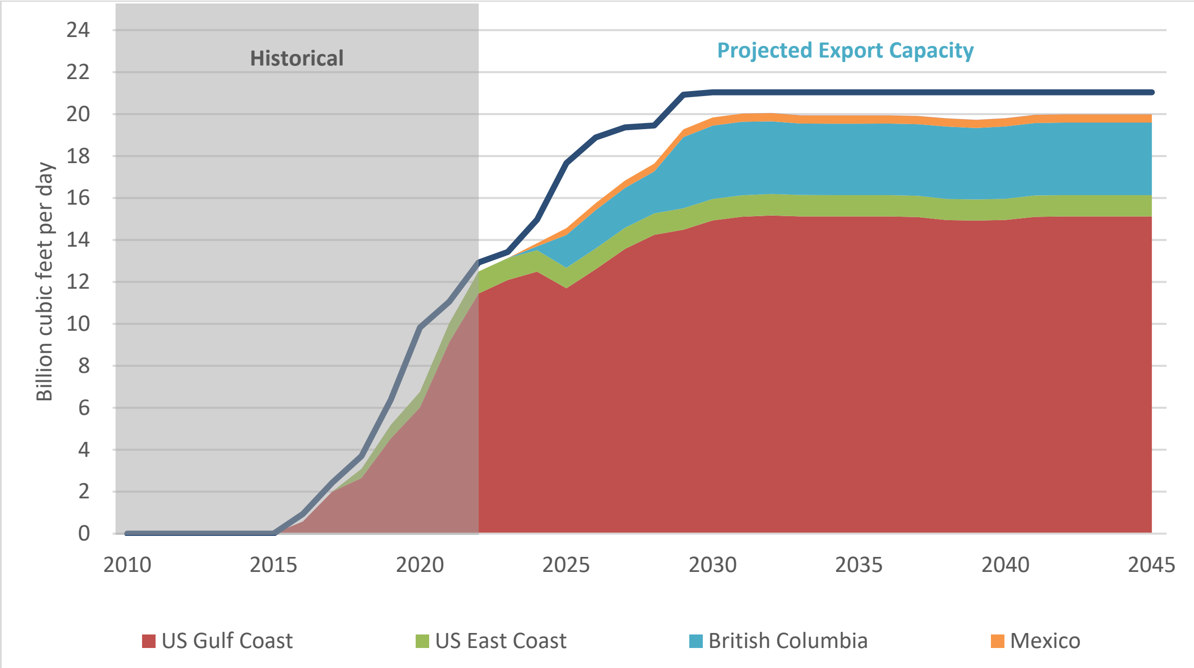


Source: ICF GMM®

ICF assumes that 12 North American LNG export terminals will be built and/or expanded: Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, Elba Island, Golden Pass, LNG Canada, Woodfibre, Calcasieu Pass, Costa Azul, and Driftwood LNG. By the end of 2022, ICF projects U.S. LNG export capacity will be 12.9 Bcfd. ICF's current projection assumes total North American LNG exports reach 15.2 Bcfd by 2025, with the majority (13.9 Bcfd) coming from the U.S. Gulf Coast.

ICF assumes an additional 8.1 Bcfd of export capacity will come online in the U.S., Canada, and Mexico between 2022 and 2045 and the North American LNG export terminal capacity utilization is projected to average about 93% through 2045.

Exhibit 2-2 : LNG Export Volume versus Capacity



Source: ICF GMM®

North American Supply Outlook

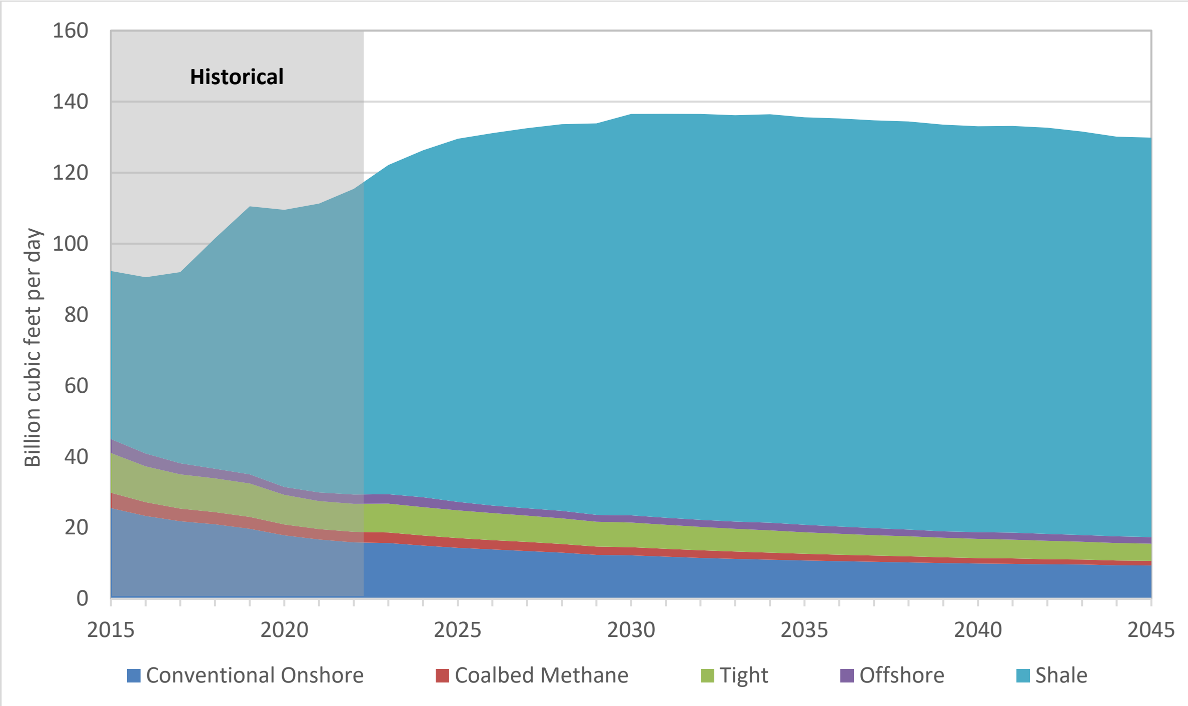
Over the past several years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production. Production is expected to grow further through 2030 and then expected to remain flat (see Exhibit B). Recent unconventional production technology advances (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional natural gas and tight oil production expected to far exceed declining conventional production.

Total U.S. and Canadian gas production is currently over 94 Bcfd, with the Marcellus/Utica accounting for over 30 percent of total North American production. Production growth has been centered in the Marcellus/Utica due to the size of the resource (estimated to be well over 1,000 trillion cubic feet) and low per-unit production costs. Natural gas production growth from the Marcellus and Utica has slowed down since lack of pipeline infrastructure is limiting movement of gas out of the basin.

Even though the oil prices are high, North American drilling activity is slower than expected in 2022 due to investor resistance to drilling expansion, lack of infrastructure, labor shortages and uncertain public policies pertaining to drilling in the US.

ICF

Exhibit 2-3 : U.S. and Canada Natural Gas Production



Source: ICF GMM®

North American Price Outlook

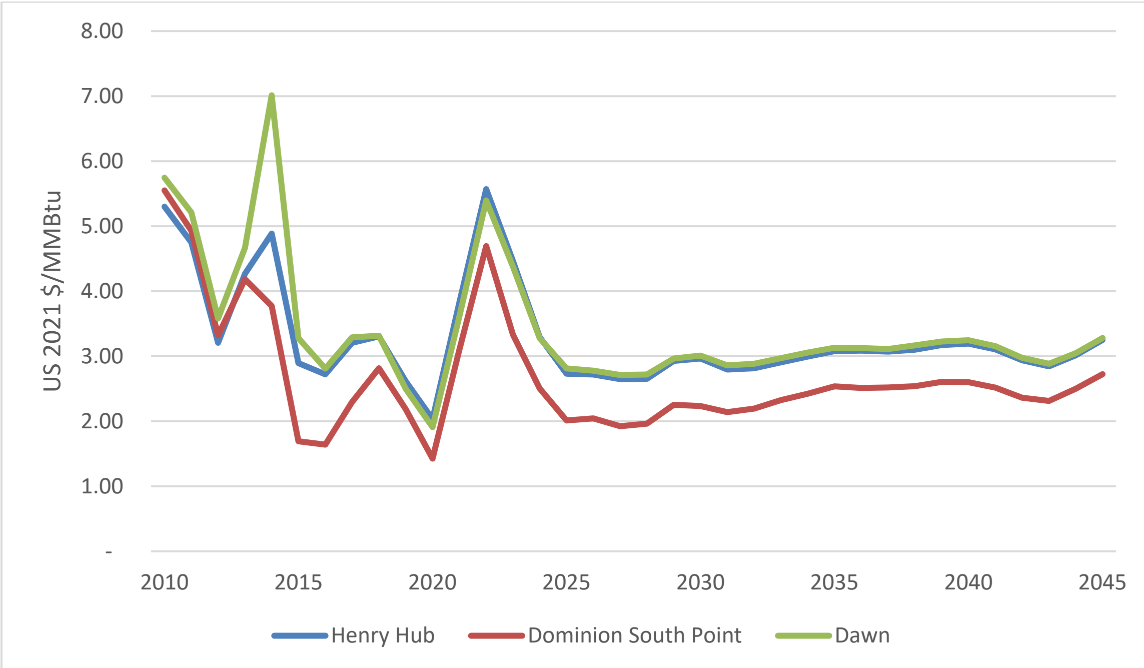
Natural gas prices at the major market hubs in North America are forecasted to be higher in 2022 than they were in 2021 due to a significant rise in LNG exports demand, low levels of natural gas in storage, slower than expected production gains and fluctuating weather.

ICF expects natural gas prices across North America to remain high in 2022 as well as 2023 given the current market conditions. The Henry Hub price is projected to average $5.57/MMBtu (in real 2021$) in 2022 and $4.47/MMBtu in 2023. Prices are expected to stay below $3.5/MMBtu in 2024-2025 (in real 2021$), under normal weather conditions, as natural gas markets rebalance with increased drilling and production activities. Between 2026-2045, prices are projected to stay between $2.65/MMBtu and $3.25/MMBtu (in 2021$).

The natural gas prices at Dawn in 2022 and 2023 are projected to average US$4.89/MMBtu amid the ongoing geopolitical tensions leading to increased demand and supply shortages. They will be under US$3.28/MMBtu from 2024 through 2030 and average about US$3.01/MMBtu (in 2021$) between 2025 and 2045.

Flows from Western Canada before 2037 and then from the Marcellus/Utica after 2037 coupled with higher gas demand in the Gulf Coast keeps the prices at Dawn near Henry Hub levels. ICF projects that Dawn will trade at a premium to Henry Hub between 2025 to 2045.

Exhibit 2-4 : Natural Gas Prices (US$) at Henry Hub, Dominion South Point, and Dawn



Source: ICF GMM

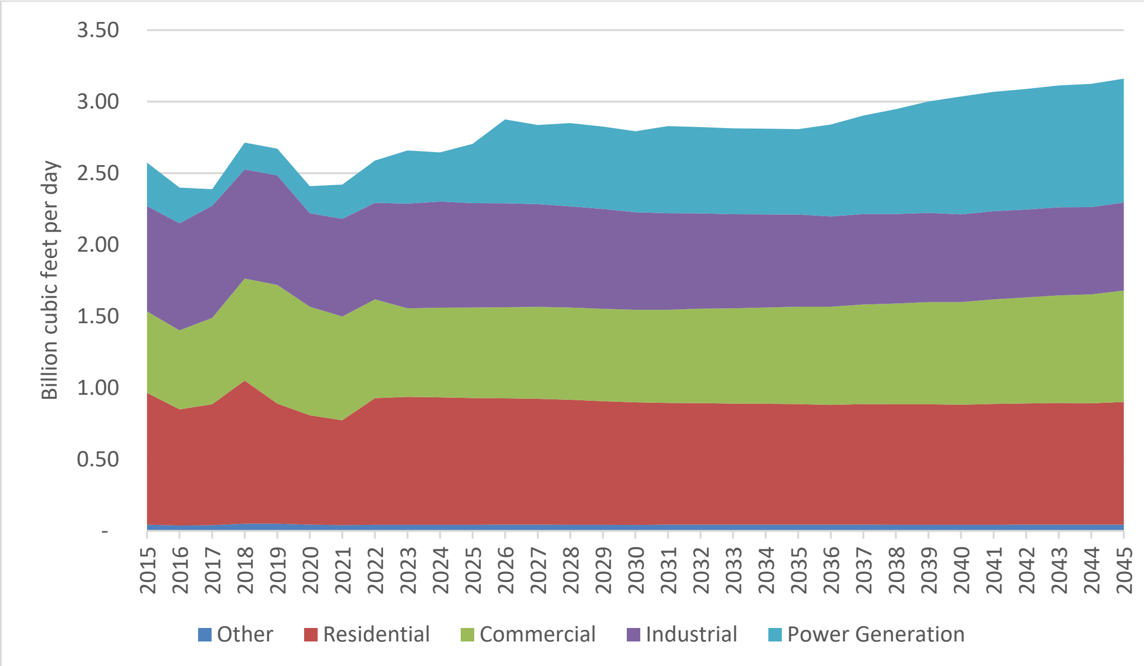
2.2 Ontario Natural Gas Market Outlook

Supply and Demand Trends

Ontario's natural gas demand in 2019 was about 2.7 Bcfd and accounted for approximately 21 percent of Canada's total natural gas demand. Demand growth was stunted between 2020-21 due to the Covid-19 pandemic but is expected to go back to the pre-pandemic levels by 2023. ICF projects Ontario's natural gas demand to average 2.9 Bcfd between 2025 to 2045.

Currently, the residential sector, which mainly relies on natural gas for space and water heating, has the largest demand for natural gas in Ontario and averages about 0.9 Bcfd annually for 2022. The residential, commercial, and industrial generation sectors together comprise over 85 percent of Ontario's natural gas demand. ICF's Q2 2022 base case expects power generation gas demand to experience the most growth during the next decade, increasing from 0.3 Bcfd in 2022 to 0.6 Bcfd in 2030. As nuclear power plants retire and access to gas from the Marcellus/Utica supply region of the U.S. improves, natural gas-fired power generation is projected to increase significantly.

Exhibit 2-5 : Ontario Natural Gas Demand



Source: ICF GMM® Case

Regional Supply Trends

Ontario has little natural gas production of its own, and thus imports practically all its supply from other regions in Canada and the United States. Ontario receives its natural gas from three main flow pathways, from Michigan, Western Canada and Niagara, with minimal volumes from Iroquois. In 2021, the largest regional supplier of natural gas to Ontario was Western Canada, which supplied 2.17 Bcfd on an average annual basis.

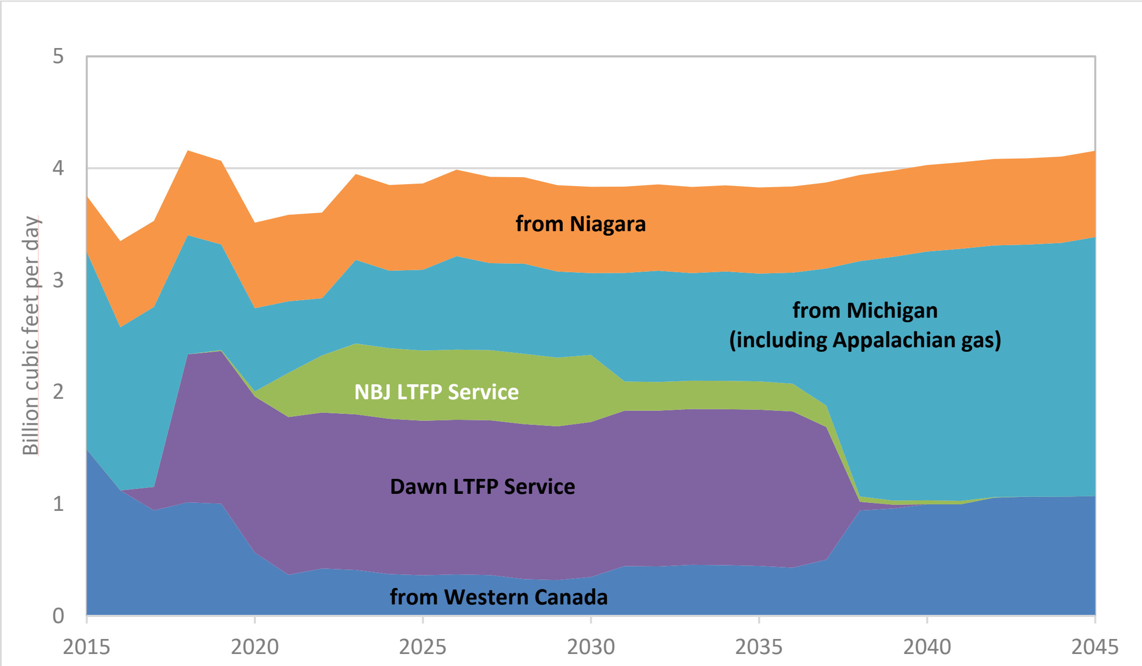
ICF projects that flows from Western Canada into Ontario will grow between 2022-2023, reaching 2.4 Bcfd by 2023 and then remain flat for the next couple of years before they start to decline in 2028.

The second biggest source of natural gas for Ontario is Michigan, which in turn sources its gas from the Midcontinent, Rockies, and the Marcellus/Utica supply region. In 2019, 0.95 Bcfd flowed from Michigan into Ontario. This was slashed by over 30 percent in 2021 due to lockdowns and reduced demand because of COVID-19 pandemic. Flows from Michigan to Ontario are projected to increase after the expiration of the Dawn LTFP service in 2037 and 2038[12]. The supply from Michigan will grow from 0.51 Bcfd in 2022 to over 2.1 Bcfd by 2038.

In recent years Marcellus/Utica gas has also been flowing northbound on the Tennessee and National Fuel pipeline systems to supply Ontario via the border crossing at Niagara, New York. By 2025 Ontario will receive 61 percent of its supplies from Western Canada, 19 percent via Michigan, and 20 percent via Niagara.

[12] The LTFP Services may be renewed prior to expiration.

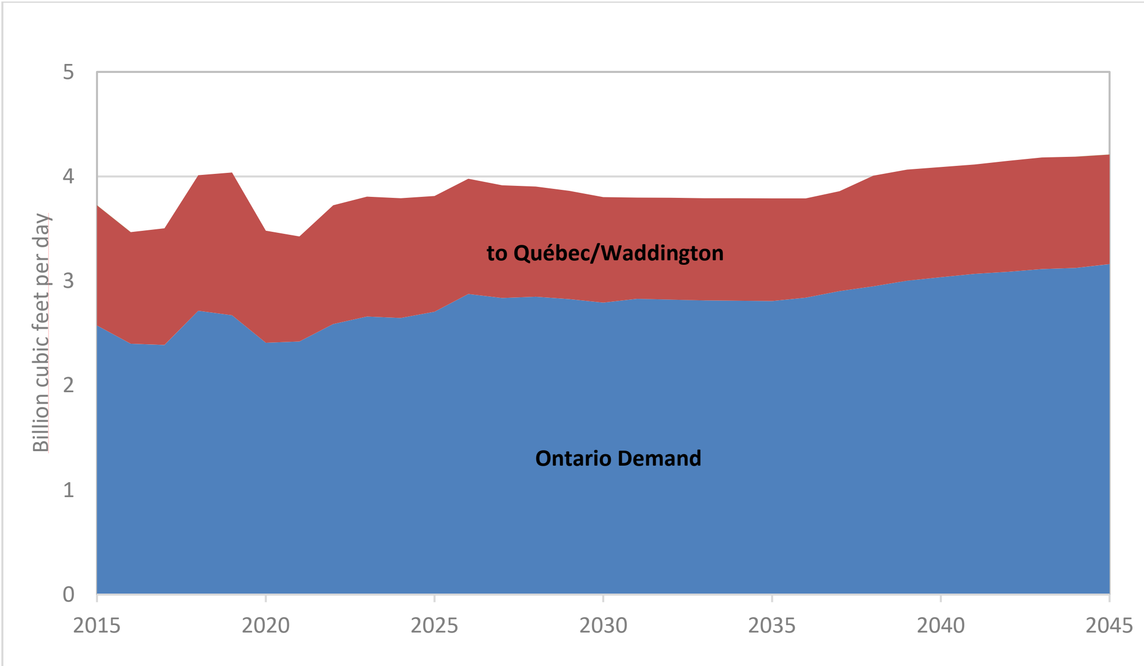
Exhibit 2-6 : Ontario Natural Gas Supply, Annual In-bound Flows



Source: ICF GMM® Case

Another important factor that will influence pipeline flows in Ontario will be the potential growth in New York and New England peak winter demand. Currently that demand growth is expected to be greater than the planned pipeline capacity additions from the Appalachian Basin directed toward that region. Flows from Ontario and Québec into the Northeastern U.S. will remain a critical component of peak period supply in the U.S. Northeast.

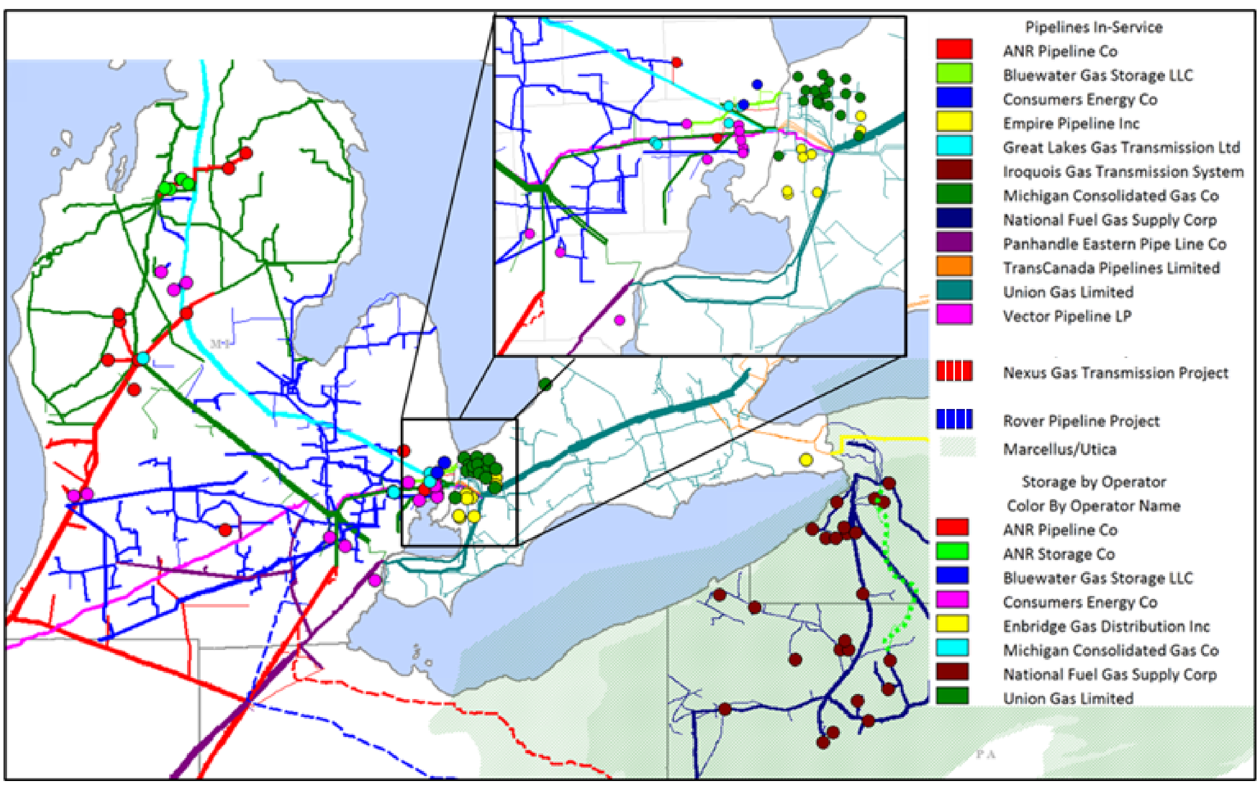
Exhibit 2-7 : Annual Ontario Demand and Out-bound Flows



Source: ICF GMM®

Exhibit 2-8 below presents a map of the infrastructure around Dawn (inset) and the pipeline network serving the broader geographic market, including storage facilities outside Ontario connected to the broader pipeline network.

Exhibit 2-8 : Pipeline and Storage Infrastructure for Ontario



Source: ABB Velocity Suite

Several pipelines that are interconnected within the broader North American gas market also feed into Dawn. These pipelines are summarized in Exhibit 2-9 below.

- Link Pipeline from EGD's Tecumseh storage field which also receives gas at the St. Clair River from the ANR pipeline that reaches back into Michigan, the Mid-Continent and Texas.
- Bluewater Pipeline feeds into Enbridge Gas at the St. Clair River, connecting Enbridge Gas to the Bluewater storage facilities in Michigan as well as to Great Lakes Pipeline, ANR, DTE Gas Pipeline (aka MichCon), and Vector Pipeline. Bluewater also offers its merchant storage customers the ability to take possession of their gas at Dawn rather than in Michigan.
- TC Energy feeds directly into the Dawn storage hub after receiving gas upstream from Great Lakes Pipeline at St. Clair River.
- The Vector Pipeline is directly connected to Dawn and reaches back to the Chicago area where the pipeline interconnects with Alliance. Vector has receipt points with ANR, DTE, Northern Border, Guardian, NEXUS, and Rover while at the Dawn end Vector connects with Enbridge Gas. Vector also interconnects with Bluewater Storage and Washington 10 Storage in Michigan. NEXUS leases capacity on Vector, allowing its customers to schedule deliveries directly to Dawn.
- DTE Gas Pipeline (MichCon) directly connects with the Dawn storage hub through Enbridge Gas at the St. Clair River. DTE pipelines are connected to production in Michigan, DTE storage facilities in Michigan, Vector, Panhandle, ANR, and NEXUS pipelines.
- Enbridge Gas also connects with the Panhandle Eastern Pipeline at Ojibway, near Windsor. Panhandle provides access to gas production in the Gulf Coast and Mid-Continent regions.
- At the other end of the system, Enbridge Gas pipelines are interconnected with TC Energy's pipeline at Kirkwall. TC Energy's line connects with the Niagara Line (National Fuel Gas, Eastern Gas, and Tennessee Gas Pipeline) at Niagara and the Empire pipeline at Chippawa. Tennessee Gas Pipeline (a Kinder Morgan company), which connects with TC Energy at Niagara provides access into the major storage fields around Ellisburg, Pennsylvania, and Marcellus production. All these pipelines are bi-directional. Today, the primary direction of flow is from New York to Ontario.

Exhibit 2-9 : Pipeline Routes and Capacity from United States to Ontario

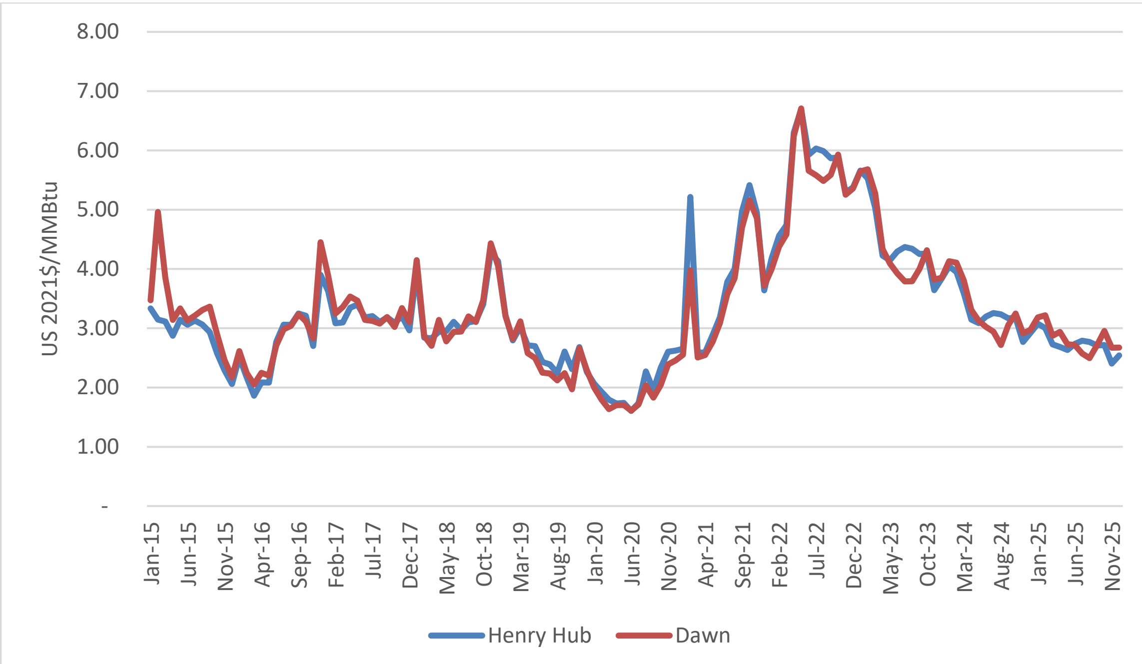
MMcf/d	Michigan to Dawn					Northwest New York to Ontario			Total
Pipeline Route	Great Lakes (St. Clair) MI into Dawn	Vector St. Clair MI to Dawn	Panhandle to Union	Bluewater to Union	MichCon to Union	Niagara (TGP to ON)	Niagara (National Fuel to ON)	Empire into ON at Chippawa	
Pipeline Import Capacity	2,100	1,745	150	257	250	825			5,327
Pipeline	Great Lakes	Vector	Panhandle	Bluewater	MichCon	Tennessee Gas Pipeline	National Fuel Gas Supply	Empire Pipeline	
Owner	TC Energy	Enbridge Gas (60%) & DTE Energy (40%)	Energy Transfer Partners	Plains GP Holdings, L.P.	DTE Energy	Kinder Morgan	National Fuel	National Fuel	
Operator	Great Lakes	Enbridge Gas	Panhandle Eastern	Bluewater Gas Storage	DTE Energy	Tennessee Gas Pipeline	National Fuel	National Fuel	

Source: ICF GMM®
***This table includes only capacity from Lower Peninsula MI to ON, and Western NY to ON*

2.3 Implications to Ontario Storage Values

The North American gas markets are in a period of transition. Gas prices in 2021 and 2022 have risen rapidly as the economy has rebounded from the recent pandemic and as international events have increased demand for LNG exports. Current natural gas prices are well above ICF's expectations for long term natural gas prices. ICF's April 2022 Base Case natural gas price forecasts for Henry Hub and Dawn used in this analysis are shown in Exhibit 2-10 below.

Exhibit 2-10 : ICF's April 2022 Base Case Monthly Gas Price (US$) Forecast for Henry Hub and Dawn



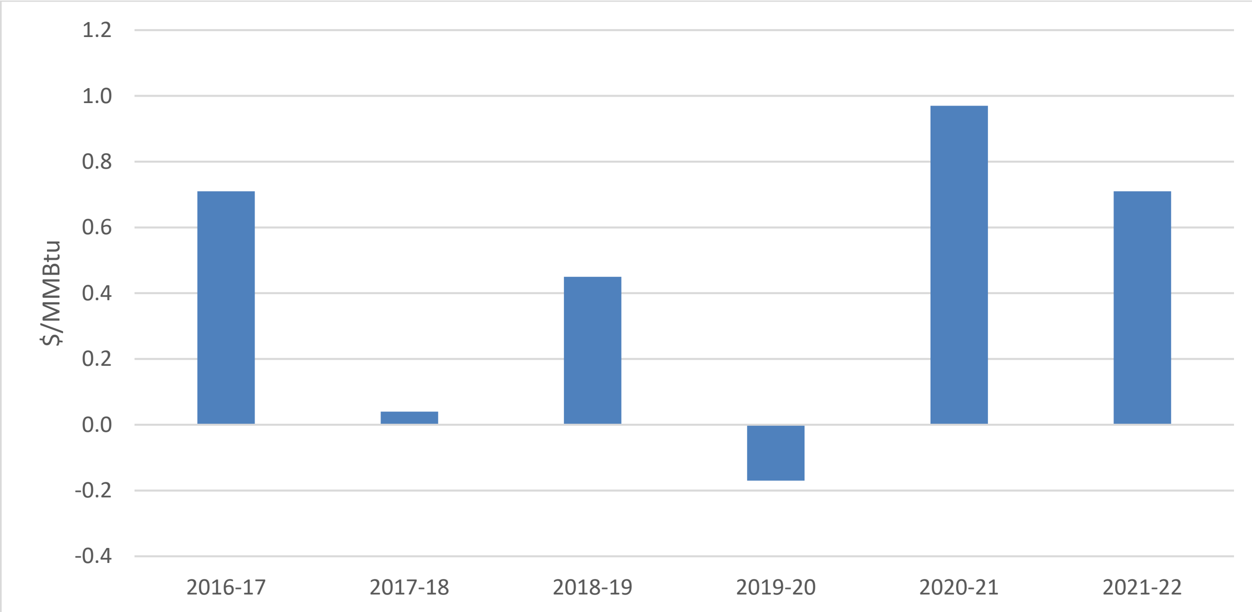
Source: ICF Gas Market Model

ICF projects that natural gas prices are likely to decline through 2025, before rebounding, and increasing slowly through 2035.

In the last year, gas price volatility has been much higher than longer term averages. ICF expects that the gas market will continue to exhibit increased gas price volatility. In the near term the increase in volatility is driven by uncertainty in international markets, and tightness in supply. Over the next two to three years, the impact of the increase in volatility will be partially offset by the impact of falling prices. In the longer term, the increase in volatility will act to further increase the value of holding natural gas storage.

Part of the value provided by natural gas storage is the ability to purchase lower priced natural gas during off peak periods to avoid the need to purchase gas during peak periods. In the case of the storage capacity used by Enbridge Gas to serve bundled service customers, this value is driven by seasonal changes in natural gas prices. As noted above, the seasonal changes in natural gas prices can vary widely from year to year. Exhibit 2-11 illustrates the swings in the seasonal value of natural gas at Dawn from the 2016/17 storage year through the 2021/2022 storage year.

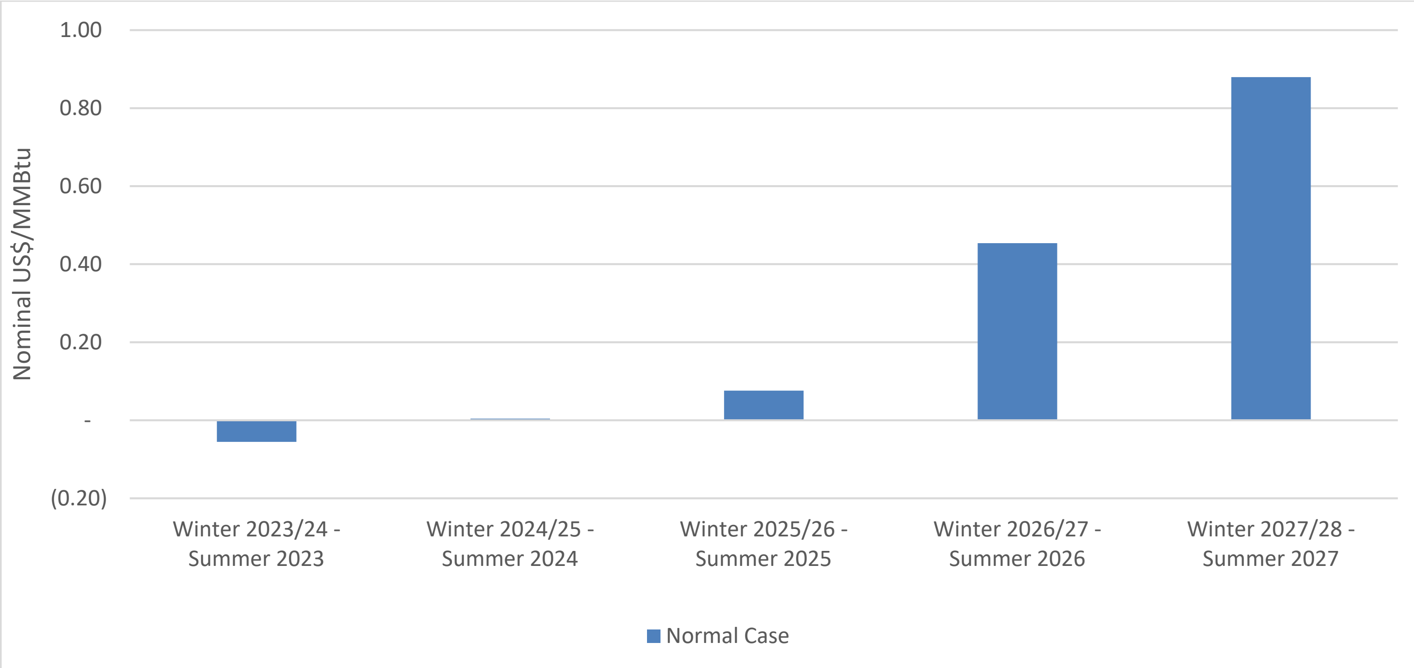
Exhibit 2-11 : Seasonal Natural Gas Price Spread at Dawn (US$/MMBtu)



Part of the variability in the seasonal natural gas price spreads is due to normal year to year market volatility related to differences in weather, supply trends, changes in natural gas exports and other seasonal factors. However, the seasonal storage values are also influenced by the longer year trends in natural gas market prices. When prices are generally increasing, the seasonal value of storage generally will be higher than average since winter gas prices are further up the increasing price path than summer prices, and when prices are generally decreasing, the seasonal value of storage generally will be lower than average since winter gas prices are further down the declining price path than summer prices.

In today's market, gas prices are higher than the long-term equilibrium price trend projected by ICF. As a result, ICF is projecting declining natural gas prices over the next couple of years, and ICF's forecast of seasonal gas price spreads are lower than average due to the projected declining natural gas price path. This trend suppresses the seasonal price spread during the 2022/23 through 2024/25 storage seasons in the ICF base case forecast.

Exhibit 2-12 : Difference between Winter and Summer prices at Dawn (US$/MMBtu)



The actual path of the price decline will be determined by market conditions, including weather, and geopolitical factors driving gas export demand that make it difficult to determine the time period where the decline in prices will occur. As a result, the price decline may occur sooner or later than projected by ICF, which will have significant impacts on the year seasonal price spread pattern in the future. ICF is currently projecting the price decline in 2022/2023 through 2024/25 to negatively impact seasonal price spreads at Dawn, although a more rapid decline in gas prices would concentrate the impact on seasonal basis into a shorter time period, potentially leading to an increase in the seasonal basis in the 2023/24 storage year if prices remain higher than expected through April 2024, or if prices fall more rapidly than expected prior to April 2023.

3 Alternatives to Market Based Storage Capacity

Enbridge Gas is proposing to use 218 PJ of storage capacity to serve in-franchise customers, including 203 PJ to serve bundled service customers. Of this, 185 PJ is utility owned cost-of- service based storage. Enbridge Gas also holds 18 PJ of market-based storage capacity to serve bundled service customers. One of the questions that Enbridge Gas asked ICF to address was whether there were viable market-based alternatives to the market-based storage capacity, and whether these alternatives would allow Enbridge Gas to hold less market-based storage capacity to serve bundled service customers. ICF concluded that there could be viable market-based alternatives to market-based storage capacity, but these alternatives would not be preferable to market-based storage capacity due to a combination of factors including economics, system reliability benefits including contributions to design day capacity planning, and reductions in supply cost volatility to consumers.

ICF considered two broad alternatives to the use of market-based storage capacity in the bundled service customer supply portfolio. The first approach was to hold additional pipeline capacity to serve the load served by the market-based storage. ICF recently reviewed the availability of pipeline capacity for Enbridge Gas as an alternative to the Dawn to Corunna pipeline. This review concluded that incremental pipeline capacity would be unlikely to be available or would require additional capacity on upstream pipelines to provide reliable winter service to Dawn and would not be a cost-effective alternative.[13] This conclusion remains valid for this analysis. In addition, the use of pipeline capacity to replace the existing market-based storage capacity would have resulted in a lower utilization rate for the pipeline capacity, increasing the costs relative to other options, and would not have reduced the long-term capital commitment relative to storage capacity. As a result, ICF does not consider incremental pipeline capacity to be an economic alternative to market-based storage.

The second alternative considered by ICF was the substitution of incremental purchases at Dawn for winter storage withdrawals, combined with winter peaking service to offset the storage contributions to design day. In this alternative, Enbridge Gas would reduce summer pipeline deliveries and summer purchases at Dawn and increase winter purchases at Dawn as the alternative to storage withdrawals. Enbridge Gas would also rely on purchases of delivered gas at Dawn to provide design day gas supply that otherwise would have been provided from the market-based storage capacity.

Dawn is a highly liquid market, and gas supplies at Dawn generally would be available for purchase. Enbridge Gas currently plans on purchases at Dawn to meet part of its supply portfolio requirements, including on a design day. Depending on the year, and depending on other market variables, including the price of market-based storage, the economics of purchasing gas at Dawn are roughly equivalent to the economics of holding market-based storage based on forecasted commodity costs. As a result, ICF considers this to be a potentially viable option for the replacement of market-based storage services. However, gas purchases at Dawn are not a perfect substitute for holding natural gas storage capacity. Storage capacity provides additional value relative to purchases at Dawn in several different areas.:

- Storage allows the purchase of gas to be shifted from the winter, when prices typically are higher, to the non-winter months when prices typically are lower.

[13] Assessment of the Value of the Enbridge Gas Dawn to Corunna Storage Project -Potential Value of Incremental Storage Capacity and Market-Based Alternatives for Enbridge Gas", ICF Resources, February 24, 2022, pages 31-35.

- Contribution of Storage Deliverability to Design Day Capacity Requirements. Storage deliverability provides a direct contribution to design day system capacity requirements. In the Gas Supply Planning model analysis, changes in storage capacity are addressed through incremental purchases at Dawn. However, purchases at Dawn do not have the degree of reliability provided by storage deliverability. The difference in reliability provides significant economic benefit to the use of incremental storage that is not captured in the Gas Supply Planning model analysis.

Increasing the reliance on winter purchases at Dawn as an alternative to holding incremental market-based storage would have significant implications on gas purchase costs. The expected increase in gas purchase costs associated with a shift from summer gas purchases to winter gas purchases would offset much or all (depending on the year) of the cost savings associated with the reduction in contracted storage capacity. In addition, the deliverability of the market-based storage capacity would need to be replaced to meet design day supply criteria. ICF's analysis suggests that during some years, reliance on winter purchases at Dawn could reduce the overall supply costs to Enbridge Gas's bundled service customers. However, in other years, this approach would lead to significant increases in costs. As a result, the reliance on increased winter purchases at Dawn would increase year-to-year gas supply cost volatility to Enbridge Gas's bundled service customers.

The reduction in the reliance on market-based storage would also impact design day planning. One of the trade-offs associated with reducing market-based storage capacity is the requirement to offset the loss of deliverability provided by the market-based storage on a design day. The most reliable market-based approach to replacing the storage deliverability likely would be delivered services provided at Dawn. Delivered Services are products offered by third parties that have firm contractual rights to pipeline capacity or storage deliverability and are willing to sell the capacity/deliverability for short durations (10 to 30 days) to meet peak demand requirements.

Delivered services are frequently relied on by utilities that have rapidly growing demand to meet incremental capacity requirements during periods when new pipeline capacity is unavailable. Delivered services contracts are generally signed for a year at a time, with no continuing obligation to provide the service beyond the contract year, and no assurances of future prices or availability.

Enbridge Gas currently relies on a significant volume of delivered services and purchases at Dawn to meet design day gas requirements in its supply plans and decreasing the market-based storage likely would further increase this reliance.

Given the liquidity of the market at Dawn, delivered service contracts likely would be available to offset the reduction in deliverability associated with a decline in contracted market-based storage. However, the cost of the delivered services contracts would further offset any potential cost savings associated with a reduction in market-based storage capacity. In addition, the cost and availability of the delivered service contracts likely will vary widely from year-to-year, leading to further increases in supply cost volatility impacting bundled service customers.

3.1 Projected Impact of Reducing Storage Capacity on Enbridge Gas' Supply Portfolio Value

In order to assess the impact on the supply portfolio of reducing storage capacity, Enbridge Gas ran the Supply Model with a 5 PJ decrement relative to the amount of storage capacity indicated by the Aggregate Excess methodology for each of the four weather scenarios evaluated. [14]

The results of the analysis indicate that reducing storage capacity below the level indicated by the Aggregate Excess methodology would result in reductions in storage demand charges. However, under the different weather scenarios, the storage demand charge savings are more than offset by the increased cost of purchasing gas supply in the winter months and peak day deliverability.

Based on this analysis, ICF determined that reducing storage capacity below the Aggregate Excess level likely would lead to an increase in the effective cost of the Enbridge Gas' supply portfolio. The results of the analysis and portfolio cost increases resulting from the 5 PJ decrement are shown in Exhibit 3-1 below:

Exhibit 3-1 : Impact of a 5 PJ Reduction in Storage Capacity on Gas Supply Portfolio Costs

Impact of Reduction in Storage Capacity on Gas Supply Portfolio Cost						
(CAD$Millions)	2023/24	2024/25	2025/26	2026/27	2027/28	Annual Average
Supply Model Portfolio Costs - Base Case Storage Capacity						
Normal Weather	3,168	2,623	2,452	2,580	2,533	2,671
Warmer than Normal Weather	2,892	2,712	2,089	4,013	2,740	2,889
Typical Weather	2,895	3,424	2,432	1,632	2,397	2,556
Colder than Normal Weather	3,291	2,909	2,881	2,700	1,773	2,711
Supply Model Portfolio Costs - 5 PJ Reduction in Storage Capacity						
Normal Weather Scenario	3,164	2,620	2,449	2,579	2,535	2,670
Warmer than Normal Weather Scenario	2,860	2,729	2,069	4,048	2,742	2,890
Typical Weather Scenario	2,875	3,448	2,425	1,612	2,415	2,555
Colder than Normal Weather Scenario	3,318	2,908	2,912	2,701	1,759	2,720
Cost of Replacing Lost Deliverability[15]	2.05	2.05	2.05	2.05	2.05	2.05
Impact of Reduced Storage Capacity on Portfolio Cost						
Normal Weather Scenario	(1.6)	(1.5)	(1.2)	1.4	4.2	0.2
Warmer than Normal Weather Scenario	(30.2)	19.9	(17.6)	36.9	4.1	2.6
Typical Weather Scenario	(17.8)	25.8	(5.6)	(18.1)	20.0	0.9
Colder than Normal Weather Scenario	28.9	1.3	32.7	3.6	(11.8)	11.0

As illustrated in Exhibit 3-1, decreasing storage by 5PJ results in average annual portfolio cost increases from a range of $0.2 million to $11.0 million, depending on the weather scenario being evaluated.

[14] The alternative weather scenarios are discussed in Section 4 of this report.
[15] The estimated value of the increase in deliverability and the value that would be derived from the increase in daily gas supply purchasing flexibility are documented in Appendix E.

4 Value of Incremental Storage Capacity to Enbridge Gas Bundled Service Customers

ICF used the analysis of North American and Ontario natural gas markets, combined with the assessment conducted by Enbridge Gas on the company's gas supply portfolio costs, to assess the impact of potential increases in natural gas storage capacity held by the company on the utility's overall gas supply portfolio cost under a variety of different weather scenarios. The analysis is summarized below.

4.1 Approach

The analysis was conducted in six steps:

1) ICF reviewed the Aggregate Excess Approach used by Enbridge Gas and estimated the amount of storage capacity consistent with the Aggregate Excess Approach based on the forecast of in-franchise bundled service demand provided by Enbridge Gas.

2) ICF specified four alternative weather scenarios to assess the impact of real-world weather on the storage capacity.

3) ICF assessed the impact on the Enbridge Gas In-franchise bundled service customer supply portfolio of reducing storage capacity below the level indicated by the Aggregate Excess Methodology. This analysis included an assessment of reducing storage capacity by 5 PJ below the level indicated by the Aggregate Excess methodology to determine the potential cost impacts of replacing storage capacity with purchases at Dawn. This analysis is reviewed in Section 3.

4) Enbridge Gas used their Supply Planning Model to evaluate the optimum storage and supply portfolio for each weather scenario.

5) ICF specified four alternative storage capacity scenarios for the Typical Weather scenario, and Enbridge Gas used their Supply Planning Model to evaluate total supply portfolio costs for each level of storage capacity.

6) ICF used the results of the Enbridge Gas's Supply Planning Model analysis of supply portfolio costs to evaluate the impact of changes in natural gas storage capacity on Enbridge Gas supply portfolio costs.

Each of these steps is described in more detail below.

4.2 Review of the Aggregate Excess Methodology

Historically, Enbridge Gas has used an aggregate excess approach to determining storage requirements, with minor differences[16] between the methodology used by EGD and Union. According to the OEB, "The aggregate excess method is the difference between the amount of gas a customer is expected to use in the 151-day winter period and the amount that would be consumed in that period based on the customer's average daily consumption over the entire year."[17]

[16] The Union approach uses only end-use demand when calculating aggregate excess, whereas the EGD approach uses system demand, including items such as lost-and-unaccounted for gas and own use gas.
[17] Ontario Energy Board, "Motions to Review the Natural Gas Electricity Interface Review Decision – Decision with Reasons" May 22, 2007. Page 59.

In essence, the aggregate excess methodology provides an estimate of the amount of storage capacity needed to optimize the utilization of contracted pipeline assets and minimize the uncertainty associated with meeting natural gas demand under normal weather conditions.

The aggregate excess approach is based on demand, rather than on the economics of storage and pipeline capacity. In and of itself, the aggregate excess methodology does not determine the optimal amount of storage capacity needed to minimize long term supply costs.

- In a market with significant excess pipeline capacity or other sources of winter gas supply being available at costs that are lower than the cost of meeting winter demand with storage, the aggregate excess methodology could result in a higher cost supply portfolio than holding a lesser amount of storage.
- In a market where prices and demand are more volatile than the normal conditions used to assess the amount of aggregate excess, and where there is limited available winter pipeline capacity or supply, or the available supply is higher cost than storage, the aggregate excess methodology could underestimate the amount of storage that should be held in an optimal supply portfolio.

The Aggregate Excess methodology is designed around normal weather. During some years, total supply costs might be lower if storage levels below the aggregate excess are included in the portfolio, and in other years, the supply costs might be lower if storage levels above the aggregate excess are included in the portfolio.

In the Ontario market, the seasonal swings in price, combined with the limited availability of incremental pipeline capacity into the storage region, and the low cost of service-based storage capacity included in the aggregate excess methodology, ICF expected that the Aggregate Excess methodology would represent the floor on the appropriate level of storage capacity. To test this hypothesis, ICF asked Enbridge Gas to provide a series of Gas Supply Planning model runs for the normal weather case and for a set of alternative weather scenarios where additional market-based storage capacity was available as part of the solution. The results of this analysis are presented in Section 4.4 and 4.5.

4.3 Alternative Weather Scenarios

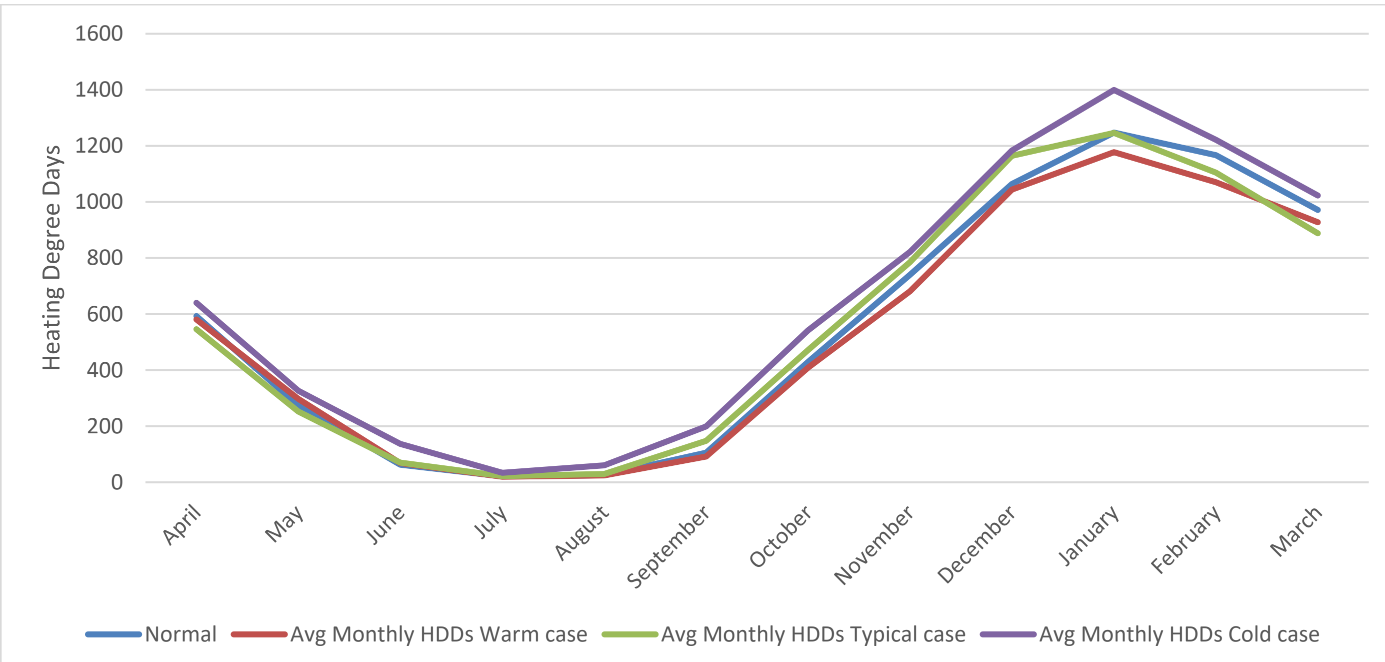
The calculation of Aggregate Excess is based on a demand forecast reflecting normal weather. The assessment of storage value for the normal weather case is influenced by two major storage drivers. The first is that normal weather analyses tend to understate the impact of market volatility on storage value. Much of the natural gas price volatility observed in the market is due to weather variation that is not captured in an analysis based on normal weather conditions. The second major point is that current market conditions impact short term forecasts. In the current natural gas market, natural gas market prices are higher than the long-term equilibrium price levels. As markets correct, the decline in prices tends to suppress the seasonal storage values calculated based on projected seasonal natural gas prices. However, the timing of the correction is uncertain, and the timing of the related changes in storage value is uncertain.

Standard variation in weather will lead to different storage valuations. During some years, total supply costs might be lower if storage levels below the aggregate excess are included in the portfolio, and in other years, the supply costs might be lower if storage levels above the aggregate excess are included in the portfolio. Incremental storage generally acts to mitigate the impacts of extreme weather conditions.

In order to provide a more realistic assessment of storage value, ICF developed a series of alternative weather scenarios. Each weather scenario was used to evaluate the Enbridge Gas' supply portfolio costs for the 5-year period from April 2023 through March 2028.

ICF used its April 2022 Gas Market Model (GMM) Base Case as the starting basis for its evaluation of the North American natural gas markets and Enbridge Gas' gas storage planning. The GMM is an internationally recognized model of the North American gas market that includes projections for natural gas demand by sector, conventional and unconventional natural gas resources, production costs, and other major gas market developments, such as potential Liquefied Natural Gas (LNG) exports. The GMM projects monthly natural gas demand, supply, and prices for more than 120 regions and is a general equilibrium market model. The model is described in more detail in Appendix C. ICF used the GMM to conduct sophisticated analysis of the potential impacts and risks associated with alternative weather scenarios on natural gas demand and prices.

Exhibit 4-1 : Average HDDs in Ontario between April 2023 to March 2028 between the alternate weather cases and normal case

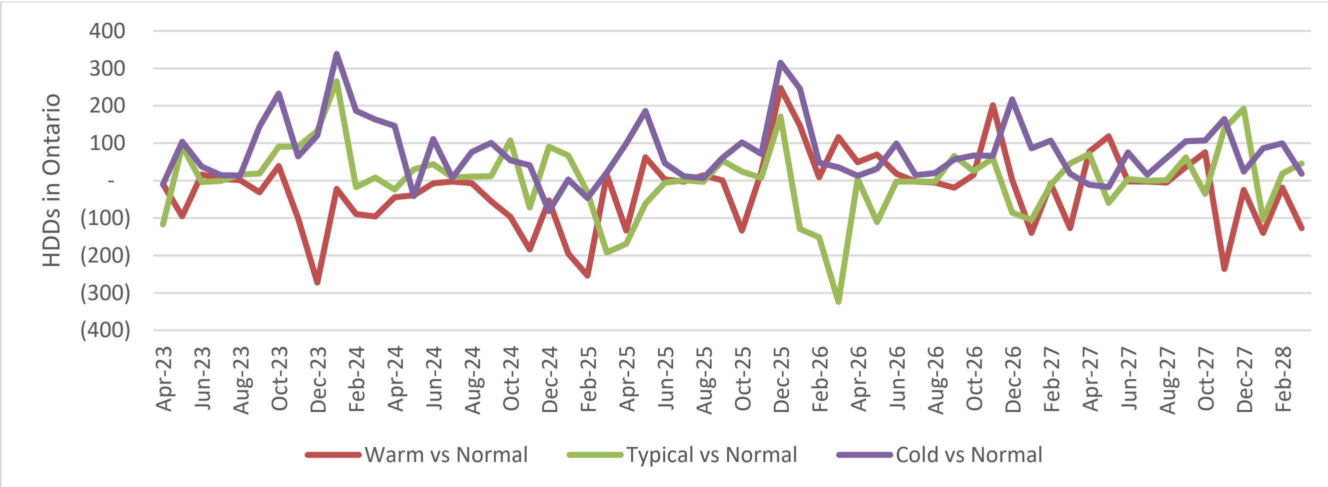


Source: ICF GMM® Case

To assess the impact of colder than normal and warmer than normal weather on prices, ICF ran 40 cases of actual 5-year weather patterns in the GMM to assess the volatility in prices with change in weather patterns.

The use of actual weather scenarios is important for estimating the actual range of impacts due to the range of positive and negative correlations between weather patterns in different regions of North America. This weather sensitivity analysis forms the basis needed to evaluate the company's gas storage operations and the impact of weather volatility on natural gas prices and basis at the natural gas market centers considered important by Enbridge Gas.

Exhibit 4-2 : Variation in the HDDs in Ontario between the alternate cases and the normal case



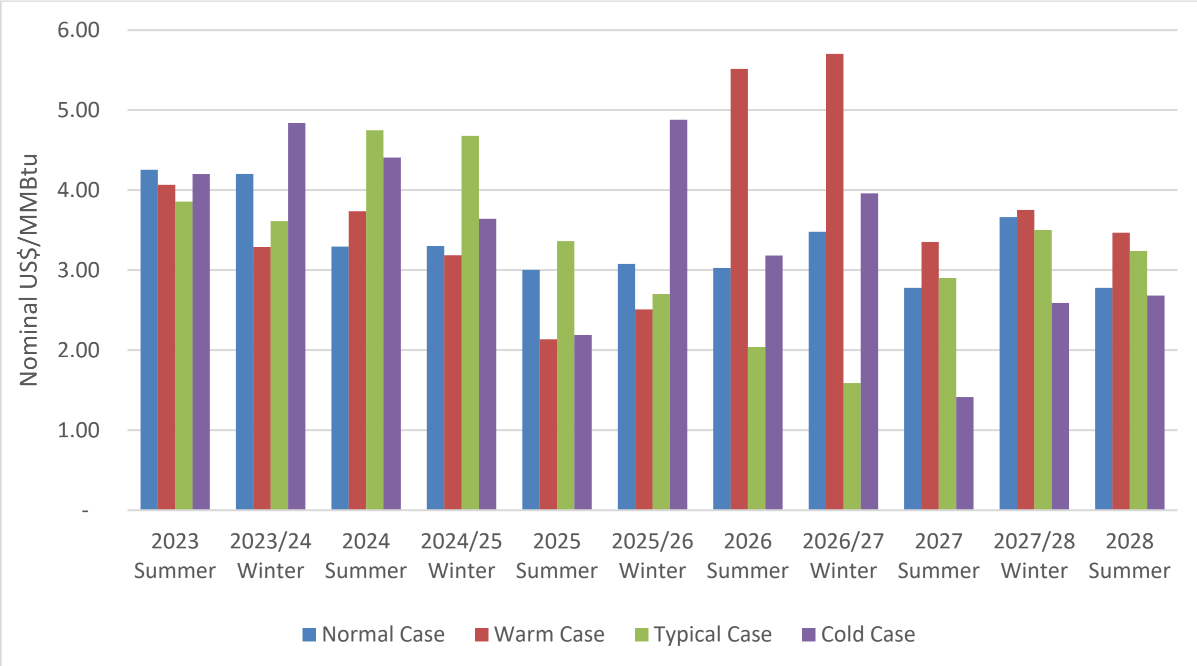
Source: ICF GMM® Case

The normal weather scenario is based on the average of the monthly HDD and CDD data for each month over the 20-year period from 2002 to 2021. ICF selected GMM's base case from April 2022 to define the normal weather scenario. The Warmer than normal weather scenario reflects an actual five-year weather period where the HDDs were lower than the normal (base) weather conditions. The Typical weather scenario is based on five years of actual weather that in total was the closest to the normal weather scenario. The Colder than normal weather scenario is based on five years of actual weather data with HDDs higher than the normal weather scenario. The three alternate weather scenarios are summarized below:

- For the **Warmer than normal Weather Scenario,** ICF selected the warmest 5-year period in Ontario[18] between 1980 to 2020 using the actual monthly HDD data. Based on this approach, 2015 – 2019 turned out to the case with lowest HDDs.
- For the **Typical Weather Scenario,** ICF selected the weather scenario which was closest to the normal weather scenario. Based on this, 2008 - 2012 turned out to be the scenario where the Ontario HDDs were closest to the normal scenario.
- For the **Colder than normal Weather Scenario,** ICF selected the coldest 5-year period in Ontario between 1980 to 2020 using the actual monthly HDD data. Based on this approach, 1981 - 1985 turned out to the case with highest HDDs.

[18] The coldest and warmest five-year periods in Ontario correspond to the coldest and warmest five-year periods in North America (U.S. and Canada).

Exhibit 4-3 : Dawn Prices (Nominal US$) Under the Four Enbridge Gas Weather Scenarios



Source: ICF Gas Market Model

The three cases based on actual weather all show significant variation in year-to-year price patterns. The year-to-year variability in prices in these three cases is due:

- Year-to-year variability in the actual weather patterns. Even during the warmest 5-year period, some years are significantly colder than the other years in the sequence leading to increases in prices. And in the coldest 5-year period, the warmer years lead to a certain amount of cycling in natural gas prices.
- Changes in market conditions due to changes in demand and prices. In the near term, natural gas market prices tend to fluctuate around a longer term normal as the market responds to price induced changes in demand and supply, and to changes in storage inventory levels created by the changes in demand. And storage inventories fluctuate around the normal seasonal levels due to changes in demand and prices, leading to year-to-year fluctuations in prices.
- Differences between Ontario weather patterns and broader North American (U.S. and Canada) weather patterns lead to regional pricing patterns that can differ from the Ontario weather patterns.

Even in the Warm Case, the price variability increases. As illustrated in Exhibit 4-2, HDD's in the warm case are higher (e.g., colder weather) than in the other cases during certain time periods, leading to increased demand and higher prices. As a result, even the warmest five-year period lead to increases in prices during certain time periods, and higher price volatility than in the normal weather case.

Alternative Storage Scenarios

The four different weather scenarios lead to significant changes in natural gas commodity prices, including both the absolute prices and the price volatility. These commodity price outlooks across the Normal, Warmer than Normal, Typical, and Colder than Normal weather cases were provided to Enbridge Gas by ICF. Enbridge Gas then used these results to assess the impact of alternative storage scenarios on Enbridge Gas natural gas supply portfolio costs using the Enbridge Gas's Supply Planning model.

The analysis uses a base gas supply portfolio which represents the bundled demand and assets that Enbridge Gas is including in its Application. The base portfolio is underpinned by the Enbridge Gas demand forecast, and upstream contract costs at the time of developing the Enbridge Gas Application. In order to complete an analysis of incremental storage, Enbridge Gas first modeled three 10 PJ tranches of incremental market-based storage and included them in the base portfolio. Enbridge Gas assumed each 10 PJ tranche was 5% more expensive than their most recent market-based storage contract[19] and assumed the contracting parameters of a standard market-based storage contract, such as 1.2% maximum deliverability and 0.75% maximum injectability. For the purposes of this analysis, Enbridge Gas assumed that the gas storage would be available at or near Dawn.[20]

Once the incremental storage tranches were included in the base portfolio, Enbridge Gas ran the Gas Supply Planning model using the application's Resource Mix optimization function for each commodity price forecast provided by ICF. With the Enbridge Gas Supply Planning model optimizing using the SENDOUT© Resource Mix function and assuming each of the ICF commodity price forecasts, the Gas Supply Planning model was used to determine what level of incremental storage, if any, provided a lower cost portfolio than the base portfolio. ICF used the results of this analysis to assess the value of holding incremental natural gas storage capacity beyond the levels currently held by Enbridge Gas for bundled in-franchise customers.

4.4 Optimized Storage Capacity for Different Weather Scenarios

Resource Mix Optimization – Total Portfolio Cost

ICF evaluated the results of the Gas Supply Planning model runs to determine the value of incremental natural gas storage capacity for each of the four weather scenarios. Exhibit 4-4 shows the maximum base storage capacity by year between the four weather scenarios. Enbridge Gas assumes 203 PJ of storage capacity across the scenarios in all the 5 years. Under normal weather conditions, the Gas Supply Planning model selected incremental storage capacity in the solution in one out of the five years evaluated. The reduction in supply costs during this one year more than offset the increase in cost of holding the incremental market-based storage capacity,

We can infer that the model is about right on Aggregate Excess storage capacity in the normal weather case and there may not be any value in procuring additional storage. However, the Warmer than normal weather case as well as the Colder than normal weather case procured incremental storage capacity in three out of the five years. The typical weather scenario picked up incremental storage in two out of the five years The results of the analysis of alternative weather patterns supports the hypothesis that the Aggregate Excess methodology generally understates the optimal amount of storage capacity that should be included in the long-term Enbridge Gas supply portfolio.

[19] The most recent market-based physical storage contract of EGI has a capacity cost of $0.83/GJ. The demand charges incurred on Tranche One (10 PJ) was $0.87/GJ, Tranche Two (10 PJ) was $0.92/GJ and Tranche Three (10 PJ) was $0.96/GJ. The variable charges for injection or withdrawal were also based off of EGI's most recent physical storage contract, which is $0.006/GJ for either injection or withdrawal.

[20] For the analysis, Enbridge Gas has assumed that new storage is available at or near Dawn and does not require incremental pipeline capacity. Hence, the Enbridge Gas's Gas Supply Planning model analysis does not include any changes to the upstream transportation portfolio, resulting in fixed transportation costs across all scenarios.

Exhibit 4-5 is a summary of the costs associated with the 203 PJ storage capacity as calculated using the Aggregate Excess methodology. Exhibits 4-6 to 4-9 outline the cost impacts of adding incremental storage outlined in Exhibit 1-2 by incremental storage cost, supply cost, transportation cost and the total supply portfolio costs by year for each of the weather scenarios.

Exhibit 4-4 : Total Existing and incremental storage (PJ) in each of the weather scenarios by year

Optimized Storage Capacity (PJ)	2023/24	2024/25	2025/26	2026/27	2027/28
Aggregate Excess Capacity					
Normal Weather Case	203	203	203	203	203
Warm Weather Case	203	203	203	203	203
Typical Weather Case	203	203	203	203	203
Cold Weather Case	203	203	203	203	203
Incremental Storage Capacity					
Normal Weather Case	-	-	-	-	10.5
Warm Weather Case	-	-	25.9	30.0	3.4
Typical Weather Case	-	19.1	-	-	25.3
Cold Weather Case	3.2	-	30.0	-	12.5
Total Optimized Storage Capacity					
Normal Weather Case	203	203	203	203	213
Warm Weather Case	203	203	229	233	206
Typical Weather Case	203	223	203	203	229
Cold Weather Case	206	203	233	203	215

Exhibit 4-5 : Total Costs when Incremental Storage is provided to each of the scenarios (Million CAD$)

Total cost (Million CAD$)	2023/24	2024/25	2025/26	2026/27	2027/28	Annual Average Total Cost
Normal Case	3,168	2,623	2,452	2,580	2,531	2,671
Warm Case	2,892	2,800	2,144	3,835	2,740	2,882
Typical Weather Case	2,991	3,315	2,432	1,632	2,385	2,551
Cold Case	3,272	2,940	2,710	2,700	1,764	2,677

The total supply portfolio costs can be broken down by Storage cost, Supply cost, and Transportation cost as provided by the Enbridge Gas using their Gas Supply Planning model results. Based on these results, ICF was able to access the change in storage, supply and transportation costs between the existing base storage capacity case and the incremental storage capacity cases. The results from the same are shown in the Exhibit 4-6 to Exhibit 4-9 below.

When additional storage capacity is provided to the model, the total supply portfolio costs go down which is driven by the decline in the supply costs associated with the procurement of more storage.

Exhibit 4-6 : Incremental Storage Costs (Million$) by year between the weather scenarios

Incremental storage costs (Million$)	2023	2024	2025	2026	2027	Annual Average
Normal Case	(0.0)	0.0	(0.0)	(0.0)	10.4	2.1
Warm Case	0.0	1.1	28.0	31.9	3.4	12.9
Typical Weather Case	0.7	19.9	0.0	(0.0)	25.1	9.1
Cold Case	3.0	0.2	31.8	0.0	11.8	9.4

Exhibit 4-7 : Incremental Supply Costs (Million$) by year between the weather scenarios

Incremental supply costs (Million$)	2023	2024	2025	2026	2027	Annual Average
Normal Case	-	-	-	-	(15.8)	(3.2)
Warm Case	0.0	86.8	24.9	(211.6)	(4.7)	(20.9)
Typical Weather Case	95.8	(130.1)	(0.0)	0.0	(39.4)	(14.7)
Cold Case	(21.9)	30.6	(207.3)	-	(23.8)	(44.5)

Exhibit 4-8 : Incremental Transportation Costs (Million$) by year between the weather scenarios

Incremental transportation costs (Million$)	2023	2024	2025	2026	2027	Annual Average
Normal Case	-	-	-	-	3.3	0.7
Warm Case	(0.0)	0.0	2.1	1.2	0.6	0.8
Typical Weather Case	0.0	1.0	0.0	(0.0)	2.1	0.6
Cold Case	0.5	-	4.1	-	3.1	1.5

Exhibit 4-9 : Incremental Total Supply Portfolio Costs (Million$) by year between the weather scenarios

Incremental Total Supply Portfolio costs (Million$)	2023	2024	2025	2026	2027	Annual Average
Normal Case	(0.0)	0.0	(0.0)	(0.0)	(2.1)	(0.4)
Warm Case	0.0	87.8	54.9	(178.5)	(0.7)	(7.3)
Typical Weather Case	96.5	(109.3)	(0.0)	(0.0)	(12.1)	(4.9)
Cold Case	(18.4)	30.8	(171.5)	0.0	(8.9)	(33.6)

4.5 Impact of Different Weather Patterns on Storage Capacity

In all the scenarios, the increase in storage capacity allows Enbridge Gas to purchase additional lower cost natural gas supply during off-peak periods for use during the winter when prices typically are higher. Exhibit 4-10 illustrates the impact of the increase in storage capacity on Enbridge Gas supply portfolio costs for these scenarios. The change in costs from the existing base storage capacity case to the incremental storage capacity case is provided in Exhibit 4-9.

As outlined in Exhibit 4-5, the total supply portfolio costs in the Normal weather scenario with existing base storage capacity are about CAD$ 2.6 billion per year which remains almost the same in the incremental storage capacity cases.

In the months where incremental storage capacity is used by the Gas Supply Planning model, the total supply portfolio costs go down. Similarly, the total supply portfolio costs go up when no incremental storage is used by the model. This happens because the model must pay for unused storage for the months where it has contracted for storage but is not using the same.

In both the Warm Weather Case and the Cold Weather case, the analysis indicated that adding 30 PJ of storage capacity could be economic during certain periods. As outlined in Exhibit 1-3, in the Warm Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$7.3 million per year, while in the Cold Weather case, the incremental storage capacity would reduce the supply portfolio cost by C$33.6 million per year.

Exhibit 4-10 : Average Annual Impact of Incremental Storage Capacity on Enbridge Gas Supply Portfolio Costs: Current Storage Capacity Costs (Million CAD$)

(CAD$Millions)	Normal (Base) Weather Scenario	Warmer than Normal Weather Scenario	Typical Weather Scenario	Colder than Normal Weather Scenario
Total Supply Portfolio Costs				
Aggregate Excess Capacity[21]	2,671	2,889	2,556	2,711
Incremental Storage Capacity[21]	2,671	2,882	2,551	2,677
Gas Supply Costs				
Aggregate Excess Capacity	2,049	2,263	1,934	2,092
Incremental Storage Capacity	2,046	2,242	1,919	2,048
Storage Costs				
Aggregate Excess Capacity	32	34	31	27
Incremental Storage Capacity	34	47	40	37
Transport Costs				
Aggregate Excess Capacity	590	592	591	591
Incremental Storage Capacity	591	592	592	593

In the Normal Weather scenario, the total supply portfolio costs in the incremental capacity case remains close to the Aggregate excess capacity case, implying that there is limited value in adding incremental storage capacity to the system. The calculation of normal weather significantly dampens the price volatility associated

[21] The difference between the 'Aggregate Excess Capacity' line and the "Incremental Storage Capacity' line is the average annual cost savings, as outlined in Exhibit 4-9.

with normal variations in weather resulting in a lower value for storage, and when optimization modeling, the use of less storage capacity.

Impact of Incremental Fixed Storage Capacity on Supply Portfolio Costs

In the analysis of the value of incremental natural gas storage under alternative weather patterns, the Gas Supply Planning model adds storage capacity on a monthly basis in the months when it is less expensive and in turn saves on the total cost based on the market condition assumptions. In actual decision making there is no certainty on the requirement of storage in a particular month. Typically, storage customers would contract for storage capacity at least for a 12-month period, or longer, rather than only during the time periods when the storage reduces costs.[22]

ICF assumed that a fixed storage capacity will be contracted in each month and that the cost of the storage contract would be incurred over the entire analysis period. ICF added the incremental storage capacity costs to the Gas Supply Planning model results in order to provide a more realistic assessment of the total storage costs. ICF assumed fixed storage costs over the 5-year period, to understand how the cost savings will change with a long-term storage commitment in each of the weather scenarios.

Based on the outcome of the Resource Mix Optimization analysis as outlined in Exhibit 4-4 ICF assumed 10 PJ of fixed storage contracts in the Normal case, 25 PJ of fixed storage contracts in the Typical weather case, and 30 PJ of fixed storage capacity contracts in the Colder than normal and Warmer than normal weather scenarios, consistent with the maximum amount of gas storage selected for any period in the Gas Supply Planning model analysis. It was observed that the cost savings go down when the storage is fixed.

The overall results of the five-year period from April 2023 through March 2028 of weather and cost scenarios are shown in Exhibit 4-13.

The total supply portfolio costs go down (cost savings associated with fixed storage contracts) by CAD$ 0.1 million in a Normal Weather case when we assume fixed capacity contracts. The cost savings decrease in the alternative weather scenarios too, with cost savings ranging between CAD$ 1.5 million and CAD$ 9.7 million. Exhibit 4-11 shows the cost savings in each of the weather scenario by year when ICF assumed fixed storage contracts of 10 PJ in Normal weather case, 25 PJ in Typical weather case and 30 PJ each in Warm and Cold weather cases. The negative values indicate the cost reductions in the fixed storage contract case vs the Base case where no incremental storage was provided. These cost savings provide an indication of the potential cost savings associated with the use of incremental storage capacity based on storage behavior with perfect foresight.

[22] Storage customers can and do contract for short term storage to fill immediate needs.

Exhibit 4-11 : Incremental Total Supply Portfolio Costs in a fixed storage capacity scenario estimated by ICF

(CAD$Millions)	2023	2024	2025	2026	2027	Annual Average
Normal Weather	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Warm Weather	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
Typical Weather	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)
Cold Weather	(9.7)	(9.7)	(9.7)	(9.7)	(9.7)	(9.7)

Exhibit 4-12 below summarizes the annual average cost of incremental storage and the cost savings per PJ of storage addition in the incremental storage capacity case and the fixed storage capacity case.

Exhibit 4-12 : Annual Average Cost per PJ of storage addition and Cost savings per PJ of storage addition in the incremental storage capacity case and the fixed storage capacity case

CAD $ Millions/PJ	Normal Weather Scenario	Warmer than Normal Weather Scenario	Typical Weather Scenario	Colder than Normal Weather Scenario
Incremental Storage Capacity Case				
Annual average cost of incremental storage	0.99	1.05	1.02	0.98
Cost Savings	-0.04	-0.80	-1.24	-2.42
Fixed Storage Capacity Case				
Annual average cost of incremental storage with fixed contracts	0.05	0.14	0.11	0.09
Cost savings with fixed contracts	-0.01	-0.08	-0.06	-0.32

4.6 Impact of Incremental Fixed Storage Capacity on Supply Portfolio Costs

ICF also evaluated, for the “typical Weather” scenario, the impact on storage costs based on current storage operational guidelines with 1.2% maximum deliverability and 0.75% maximum injectability. For this analysis, ICF requested that Enbridge Gas use their gas supply planning model to evaluate the “Typical Weather” scenario using different levels of incremental storage capacity, including 5 PJ, 8 PJ, 10 PJ and 20 PJ above the level indicated by the aggregate excess methodology. This analysis calculates the cost of holding these different levels of incremental storage capacity over the 5-year period, as this more closely resembles how a utility would contract for and use storage capacity relative to the resource optimization analysis.

ICF based the Fixed Storage Capacity Analysis on the typical weather scenario rather than the Normal Weather scenario since the typical weather case is a better representation of how weather conditions impact price volatility and drive storage value.[23]

The results of the analysis are shown in Exhibit 4-13 and summarized in Exhibit 4-14. The analysis illustrates the impact of the adjustments for the value of deliverability based on the delivered services costs and the ability to minimize gas purchases during the highest price periods.

- Contribution of Storage Deliverability to Design Day Capacity Requirements. Storage deliverability provides a direct contribution to design day system capacity requirements. In the Gas Supply Planning model analysis, changes in storage capacity are addressed through incremental purchases at Dawn. However, purchases at Dawn do not have the degree of reliability provided by storage deliverability. The different in reliability provides significant economic benefit to the use of incremental storage that is not captured in the Gas Supply Planning model analysis.
- Contribution Value of Daily Gas Supply Purchasing Flexibility. Storage capacity allows for a more flexible gas purchasing approach that allows the utility to shift purchases on high priced days to purchases on lower priced days. This provides a direct economic benefit to the use of storage that is not captured in the use of storage to address aggregate excess requirements, or through the use of monthly average prices.

The estimated value of the increase in deliverability and the value that would be derived from the increase in daily gas supply purchasing flexibility are documented in Appendix E.

[23] Given the results of the Resource Mix Optimization analysis, it was clear that additional storage would provide additional benefits in the warm and cold weather scenarios, hence the additional analysis would not have provided sufficient value to justify the level of effort required and was not conducted,

Exhibit 4-13 : Impact of Different levels of Storage Capacity on the Total Supply Costs for the Typical Weather Scenario (Million$)

Total Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario (Million$)					
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
2023-24	2,991	2,920	2,924	2,926	2,936
2024-25	3,315	3,398	3,380	3,381	3,392
2025-26	2,432	2,445	2,455	2,459	2,471
2026-27	1,632	1,653	1,666	1,668	1,679
2027-28	2,385	2,380	2,370	2,363	2,330
2023-2028	12,755	12,796	12,795	12,797	12,808

Incremental Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario (Million$)					
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
2023-24	-	(70.8)	(67.0)	(65.0)	(54.9)
2024-25	-	83.0	65.5	66.2	77.9
2025-26	-	12.7	22.5	26.3	38.2
2026-27	-	20.8	33.7	35.8	46.4
2027-28	-	(4.8)	(14.9)	(21.7)	(55.0)
2023-2028	-	40.8	39.8	41.5	52.7
Percentage Change in Costs		0.320%	0.312%	0.326%	0.413%

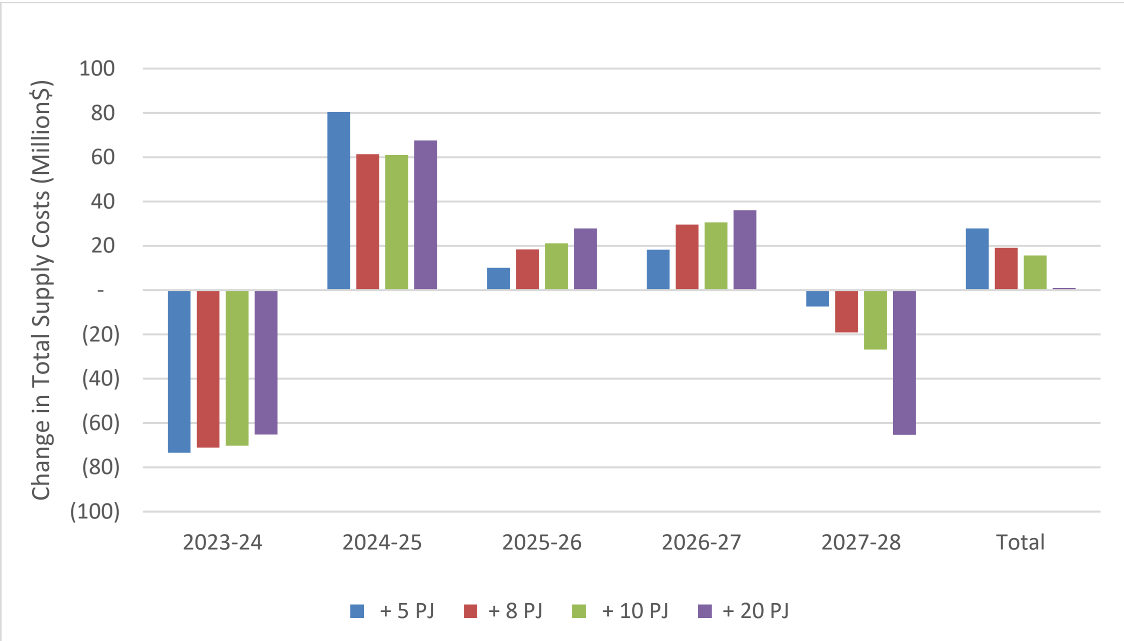
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
Value of Incremental Deliverability	-	2.1	3.3	4.1	8.2
Reduction in Gas Purchase Costs	-	0.5	0.9	1.1	2.1

Total Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario With Adjustment for Value of Incremental Deliverability (Million$)					
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
2023-24	2,991	2,918	2,920	2,921	2,926
2024-25	3,315	3,395	3,376	3,376	3,382
2025-26	2,432	2,442	2,451	2,453	2,460
2026-27	1,632	1,651	1,662	1,663	1,668
2027-28	2,385	2,378	2,366	2,358	2,320
2023-2028	12,755	12,783	12,775	12,771	12,756

Incremental Supply Costs with Different Levels of Storage Capacity for the Typical Weather Scenario (Million$)					
	203 PJ	208 PJ	211 PJ	213 PJ	223 PJ
2023-24	-	(73.4)	(71.2)	(70.2)	(65.2)
2024-25	-	80.4	61.4	61.0	67.6
2025-26	-	10.1	18.4	21.1	27.9
2026-27	-	18.2	29.6	30.6	36.1
2027-28	-	(7.4)	(19.1)	(26.9)	(65.3)
2023-2028	-	27.9	19.1	15.7	1.0
Percentage Change in Costs		0.219%	0.150%	0.123%	0.008%

As indicated in Exhibit 4-14, in the typical weather scenario, additional storage capacity reduced overall costs in 2023/24 and in 2027/28, but resulted in an increase in costs in 2024/25, 2025/26, and 2026/27. Over the 5-year period, total costs were relatively flat across the range of incremental storage capacity. Costs changed by between 0.008% and 0.2% relative to the total supply portfolio cost depending on the amount of incremental storage capacity. This is in line with expectations given the price of storage capacity used in the analysis reflects actual storage contracts signed in the recent past, where we would anticipate that the storage cost reflects the value associated with the storage capacity.

Exhibit 4-14 : Impact of Incremental Storage Capacity on Supply Costs (Million$) in the Typical Weather Cases



Summary of Resource Mix Optimization and Fixed Storage Capacity Analysis

Exhibit 4-15 is a summary of the portfolio costs savings reflected in the analysis above, under both the Resource Mix Optimization analysis, and the Fixed Storage Capacity analysis. As outlined in Exhibit 4-15, total portfolio costs decrease in all scenarios evaluated.

Exhibit 4-15 : Average Annual Change in Total Gas Costs from Incremental Storage Capacity from Enbridge Gas SENDOUT© Results (Million CAD$)

Average Annual Impact of Incremental Storage Capacity on Enbridge Gas' Supply Portfolio Costs for the Five-Year Period from April 2023 to March 2028	
(CAD$Millions)	**Reference Storage Costs**
Normal Weather Scenario	
Aggregate Excess Storage Capacity	2671
Incremental Storage Capacity[24]	-0.4
Assuming Incremental Fixed Storage Capacity	-0.1
Warmer than Normal Weather Scenario	
Aggregate Excess Storage Capacity	2889
Incremental Storage Capacity	-7.3
Assuming Incremental Fixed Storage Capacity	-2.4
Typical Weather Scenario	
Aggregate Excess Storage Capacity	2556
Incremental Storage Capacity	-5.0
Assuming Incremental Fixed Storage Capacity	-1.5
Colder than Normal Weather Scenario	
Aggregate Excess Storage Capacity	2711
Incremental Storage Capacity	-33.6
Assuming Incremental Fixed Storage Capacity	-9.7

Based on the assessment of natural gas market trends, expected natural gas prices at Dawn, and the value of natural gas storage as part of the Enbridge Gas overall supply portfolio, ICF's analysis of natural gas markets in and around the Enbridge Gas distribution service territory, and Enbridge Gas' gas supply planning model analysis indicates that there is likely to be long term cost savings with holding additional storage capacity above the level indicated by the Aggregate Excess methodology for the use of in-franchise bundled customers. This analysis indicates that additional storage capacity that would be contracted at market-based rates would reduce the long-term average cost of gas for Enbridge Gas in-franchise customers. The cost savings range from $0.1 million per year in the Normal Weather case to $9.7 million per year in the Colder than Normal Weather scenario.

[24] The incremental storage capacity costs included in this table reflect Resource Mix Optimization cost, as outlined in Exhibit 1-3

5. Recommendations and Conclusions

Enbridge Gas estimated an aggregate excess storage capacity for bundled service customers of 203 PJ for the 2023-24 storage year. This value increases to 208 PJ by the 2027/28 storage year based on projected natural gas demand growth within this customer group. Given 185 PJ of utility owned storage capacity valued at the cost of service, this would require 18 PJ of market-based storage in 2023/24, increasing to 23 PJ of market-based storage in 2027/28.

Based on our assessment of storage economics and the value of storage in reducing customer cost volatility, ICF would consider the estimate of the Aggregate Excess to represent a lower bound on the appropriate level of storage capacity needed to serve in-franchise bundled service customers rather than the optimal amount. ICF's assessment of storage value under different weather conditions and time periods suggests that Enbridge Gas should hold a certain amount of additional market-based storage capacity above this level to meet design day system capacity requirements, to increase system reliability and reduce cost volatility to Enbridge Gas customers, and potentially to reduce overall costs to Enbridge Gas customers.

The overall amount of incremental capacity that should be considered by Enbridge Gas will depend on the cost of the incremental storage at the time that Enbridge Gas goes into the market to acquire the storage[25] and the level of importance Enbridge Gas, the OEB, and other stakeholders place on minimizing long term supply costs vs. the risk of holding additional storage capacity in years where the incremental value provided by the additional storage capacity does not exceed the cost.

ICF's analysis of the potential value of storage during unusual weather and market conditions indicates that up to 25 PJ of additional market-based storage capacity could provide value to Enbridge Gas bundled service customers in the "Typical Weather" Scenario, and up to 30 PJ of additional market-based storage capacity could provide value to Enbridge Gas bundled service customers in the Colder than Normal and Warmer than Normal weather scenarios. However, the incremental fixed cost of this additional storage capacity would lead to higher costs in many years and would require additional fixed cost commitments that reduce the attractiveness of holding additional storage capacity. In addition, fully achieving the benefits of the incremental storage capacity would require the ability to optimize gas supply purchase patterns.

Instead of the maximum amount of indicated storage capacity, ICF's analysis suggests that Enbridge Gas should consider increasing the amount of market-based storage capacity held for bundled service customers by about 10 PJ from 18 PJ to 28 PJ. This recommendation reflects a balance between cost, cost volatility, design day reliability, and minimizing up front contract cost commitments for supply services based on the results of the assessment of the value of storage under different weather conditions, and the assessment of the impacts of different levels of storage capacity on costs for the typical weather scenario. The recommendation is based on both the analysis of alternative weather scenarios, and the analysis of alternative storage capacity levels for the "Typical Weather" scenario. Overall, supply costs for bundled in-franchise customers remained relatively flat across a range of storage capacity options. The supply portfolio costs changed by between 0.008% and 0.2%

[25] Given expectations about changes in the future seasonal value of natural gas, long term storage costs are expected to be lower in the next two years than thereafter, providing incentives to lock in longer term storage capacity in the near term.

relative to the total supply portfolio cost depending on the amount of incremental storage capacity provided in the typical weather case. The values increased in the Colder than Normal and Warmer than Normal scenarios, with the Colder than Normal scenario yielding a larger return of close to $9.7 million per year.

In the analysis of alternative weather scenarios, ICF's recommendation is generally consistent with the annual average of incremental storage capacity over the five-year period for the Typical Weather Scenario between 2023 and 2028, which 44.4 PJ in total over the five-year period, or about 10 PJ per year, as well as the Warm Weather Scenario and Cold Weather Scenario, which averaged 10.5 PJ per year.

The analysis of incremental storage value for the Typical Weather scenario indicated that increasing the incremental storage capacity above the level indicated by the Aggregate Excess by between 5 and 20 PJ of capacity would reduce gas supply costs during the first year of the analysis (Storage year 2023/24) and would have essentially no impact on costs over the five-year period from 2023 through 2028. In addition, the incremental storage capacity would increase system reliability and resiliency and is expected to lead to additional cost savings due to the flexibility in gas purchase timing facilitated by the incremental storage capacity. However, the cost savings resulting from going from 10 PJ of incremental storage to 20 PJ of incremental storage are small and may not offset the impact of the commitment for additional storage capacity.

Hence, based on the analysis of both the potential value of storage under different weather conditions, and the value of incremental storage capacity in the "Typical Weather" scenario, ICF recommends the 10 PJ of incremental storage capacity as the best balance between the projected value of the incremental storage capacity to minimize gas supply costs, the value of reducing gas cost uncertainty and volatility, and the reliability benefits provided by storage capacity, and the fixed cost commitments needed to contract for the storage capacity.

Appendix A: Natural Gas Prices at Dawn for the Four Alternative Weather Scenarios

Exhibit A 1: Natural Gas Prices at Dawn for the Four Enbridge Gas Weather Scenarios

Prices at Dawn - Nom US$/MMBtu	Normal Case	Warm Case	Typical Case	Cold Case
2023 Summer	4.3	4.1	3.9	4.2
2023/24 Winter	4.2	3.3	3.6	4.8
2024 Summer	3.3	3.7	4.7	4.4
2024/25 Winter	3.3	3.2	4.7	3.6
2025 Summer	3.0	2.1	3.4	2.2
2025/26 Winter	3.1	2.5	2.7	4.9
2026 Summer	3.0	5.5	2.0	3.2
2026/27 Winter	3.5	5.7	1.6	4.0
2027 Summer	2.8	3.4	2.9	1.4
2027/28 Winter	3.7	3.8	3.5	2.6
2028 Summer	2.8	3.5	3.2	2.7

Source: ICF GMM®

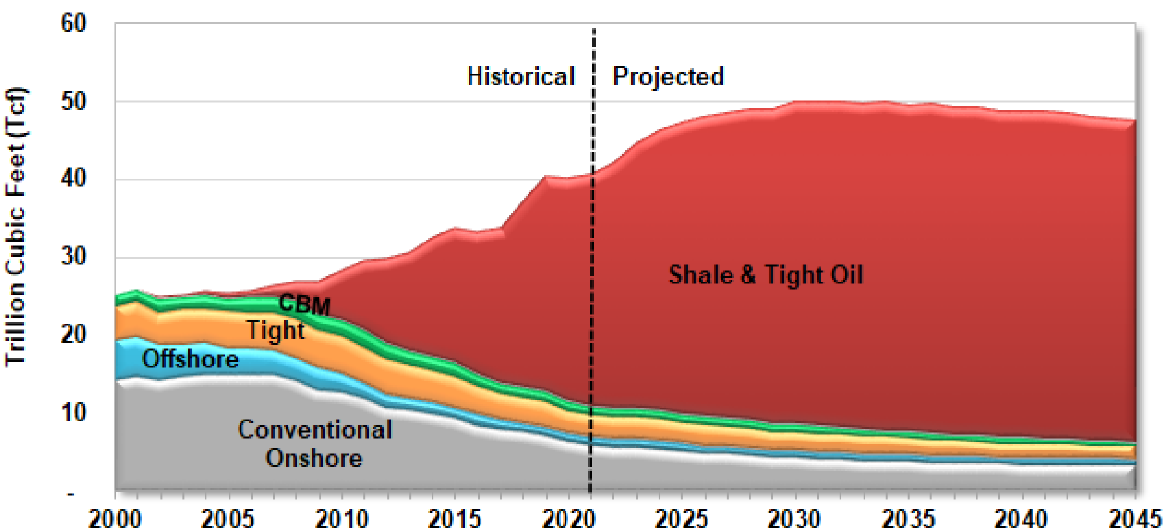
Appendix B: Assumptions behind ICF's Natural gas Market Outlook – April 2022

This section discusses U.S. and Canadian Base Case natural gas market forecasts, starting with natural gas supply trends, including ICF's resource base assessment and comparisons with other assessments. The section then discusses trends in U.S. and Canadian demand through 2045, including pipeline construction and LNG export trends. The section concludes with forecasts on U.S. and Canadian natural gas pipeline and international trade and natural gas prices.

U.S. and Canadian Natural Gas Supply Trends

Over the past several years, natural gas production in the U.S. and Canada has grown quickly, led by unconventional production. Production is expected to grow further through 2030 and then expected to remain flat (see Exhibit B 1). Recent unconventional production technology advances (i.e., horizontal drilling and multi-stage hydraulic fracturing) have fundamentally changed supply and demand dynamics for the U.S. and Canada, with unconventional natural gas and tight oil production expected to far exceed declining conventional production. These production changes have incentivized significant infrastructure investments to create pathways between new supply sources and demand markets.

Exhibit B 1 : U.S. and Canadian Gas Supplies



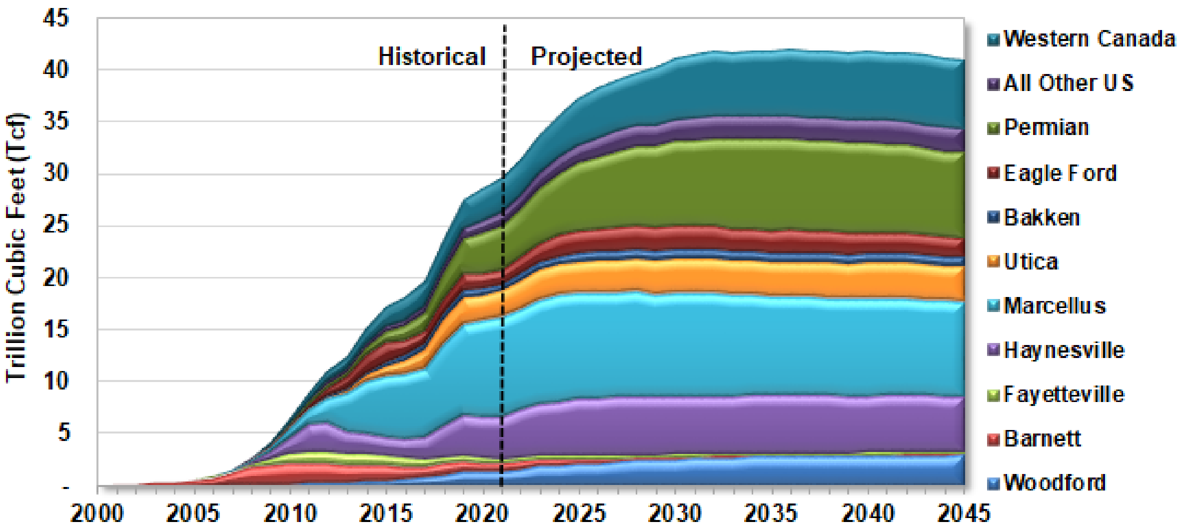
Source: ICF GMM® Q2 2022

Production from U.S. and Canadian shale formations will grow from 31.4 Tcf per year (86.1 Bcfd) in 2022 or 75 percent of total production to 41.1 Tcf per year (112.5 Bcfd) by 2045 or 87 percent of total production (see exhibit above). The projection assumes West Texas Intermediate (WTI) crude price of $70/Bbl ($2021).

The major shale formations in the U.S. and Canada are in the U.S. Northeast (Marcellus and Utica), the Mid-continent and North Gulf States (Woodford, Fayetteville, Barnett, and Haynesville), South Texas (Eagle Ford), and western Canada (Montney and Horn River). The Permian, Niobrara, and Bakken are primarily producing oil with associated natural gas volumes. Associated gas production from the Permian, Niobrara, and Bakken is expected to grow significantly in the next 10 years. Dry gas[26] production from the lower cost Permian basin will reach 8.2 Tcf per year (22.6 Bcfd) by 2045, mostly gas associated with tight oil, from about 4.7 Tcf (12.8 Bcfd) in 2022.

ICF did not include in our forecast potential shale and tight oil formations in the U.S. and Canada that have not yet been evaluated or developed for gas and oil production.

Exhibit B 2 : U.S. and Canadian Shale Gas Production



Source: ICF GMM® Q2 2022

Natural Gas Production Costs

ICF estimates that production of unconventional natural gas (including shale gas, tight gas, and coalbed methane (CBM) will generally have much lower cost on a per-unit basis than conventional sources.[27] The gas supply curves show the incremental cost of developing different types of gas resources, as well as for the resource base in total. Even though their production costs are uncertain due the newness of the plays and considerable site-to-site variation in geology, shale plays such as the Marcellus and Permian and other tight oil plays are proving to be among the least expensive (on a per-unit basis) natural gas sources.

ICF has developed resource cost curves for the U.S. and Canada. These curves represent the aggregation of discounted cash flow analyses at a highly granular level. Resources included in the cost curves are all the resources discussed above – proven reserves, growth, new fields, and unconventional gas. The detailed unconventional geographic information system (GIS) plays are represented in the curves by thousands of individual discounted cash flow (DCF) analyses.

Conventional and unconventional gas resources are determined using different approaches due to the nature of each resource. For example, conventional new fields require new field wildcat exploration while shale gas and tight oil are almost all development drilling. Offshore undiscovered conventional resources require special analysis related to production facilities as a function of field size and water depth.

The basic ICF resource costs are determined first "at the wellhead" prior to gathering, processing, and

[26] Dry gas is natural gas which remains after processing plant separation, also known as consumer-grade natural gas.
[27] Unconventional refers to production that requires some form of stimulation (such as hydraulic fracturing) within the well to produce gas economically. Conventional wells do not require stimulation.

transportation. Then, those cost factors are added to estimate costs at points farther downstream of the wellhead. Costs can be further adjusted to a "Henry Hub" basis by adding regional basis differentials for certain type of analysis that considers the locations of resources relative to markets.

Supply Costs of Conventional Oil and Gas

Conventional undiscovered fields are represented by a field size distribution. Such distributions are typically compiled at the "play" level. Typically, there are a few large fields and many small fields remaining in a play. In the model, these play-level distributions are aggregated into 5,000-foot drilling depth intervals onshore and by water depth intervals offshore. Fields are evaluated in terms of barrels of oil equivalent, but the hydrocarbon breakout of crude oil, associated gas, non-associated gas, and gas liquids is also determined. All areas of the Lower-48, Canada, and Alaska are evaluated.

Costs involved in discovering and developing new conventional oil and gas fields include the cost of seismic exploration, new field wildcat drilling, delineation and development drilling, and the cost of offshore production facilities. The model includes algorithms to estimate the cost of exploration in terms of the number and size of discoveries that would be expected from an increment of new field wildcat drilling.

Supply Costs of Unconventional Oil and Gas

ICF has developed models to assess the technical and economic recovery from shale gas and other types of unconventional gas plays. These models were developed during a large-scale study of North America gas resources conducted for a group of gas-producing companies and have been subsequently refined and expanded. North American plays include all the major shale gas plays that are currently active. Each play was gridded into 36 square mile units of analysis. For example, the Marcellus Shale play contains approximately 1,100 such units covering a surface area of almost 40,000 square miles.

The resource assessment is based upon volumetric methods combined with geologic factors such as organic richness and thermal maturity. An engineering-based model is used to simulate the production from typical wells within an analytic cell. This model is calibrated using actual historical well recovery and production profiles.

The wellhead resource cost for each 36-square-mile cell is the total required wellhead price in dollars per MMBtu needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes, and income taxes.

Wellhead economics are based upon discounted cash flow analysis for a typical well that is used to characterize each cell. Costs include drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, and such costs are based upon cost per stage and number of stages. Per-foot drilling costs were based upon analysis of industry and published data. The American Petroleum Institute (API) Joint Association Survey of Drilling Costs and Petroleum Services Association of Canada (PSAC) are sources of drilling and completion cost data, and the U.S. Energy Information Administration (EIA) is a source for operating and equipment costs.28,29,30 Lateral length, number of fracturing stages, and cost per fracturing stage assumptions were based upon commercial well databases, producer surveys, investor slides, and other sources.

In developing the aggregate North American supply curve, the play supply curves were adjusted to a Henry Hub, Louisiana basis by adding or subtracting an estimated differential to Henry Hub. This has the effect of adding costs to more remote plays and subtracting costs from plays closer to demand markets than Henry Hub.

The cost of supply curves developed for each play include the cost of supply for each development well spacing. Thus, there may be one curve for an initial 120-acre-per-well development, and one for a 60-acre-per-well option.

[28] American Petroleum Institute. "Joint Association Survey of Drilling Costs". API, 2012 and various other years: Washington, DC.
[29] Petroleum Services Association of Canada (PSAC). "Well Cost Study". PSAC, 2009 and various other years. Available at: http://www.psac.ca/
[30] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs". EIA, 2011 and various other years: Washington, DC. Available at: http://www.eia.gov/petroleum/reports.cfm

This approach was used because the amount of assessed recoverable and economic resource is a function of well spacing. In some plays, down spacing may be economic at a relatively low wellhead price, while in other plays, economics may dictate that the play would likely not be developed on closer spacing. The factors that determine the economics of infill development are complex because of varying geology and engineering characteristics and the cost of drilling and operating the wells.

The initial resource assessment is based on current practices and costs and, therefore, does not include the potential for either upstream technology advances or drilling and completion cost reductions in the future. Throughout the history of the gas industry, technology improvements have resulted in increased recovery and improved economics. In ICF's oil and gas drilling activity and production forecasting, assumptions are typically made that well recovery improvements and drilling cost reductions will continue in the future and will have the effect of reducing supply costs. Thus, the current study anticipates there will be more resources available in the future than indicated by a static supply curve based on current technology.

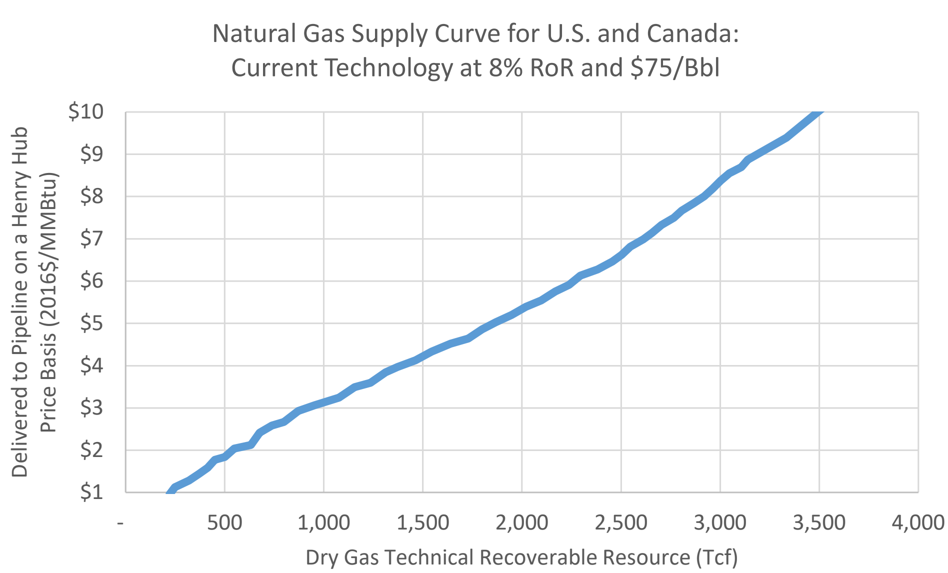
Aggregate Cost of Supply Curves

U.S. and Canadian supply cost curves (based on current technology) on a "Henry Hub" price basis are presented in Exhibit B 3. The supply curves were developed on an "oil-derived" basis. That is to say, the liquids prices are fixed in the model (crude oil at $75 per barrel) and the gas prices in the curve represent the revenue that is needed to cover those costs that were not covered by the liquids in the DCF analysis. The rate of return criterion is 8 percent, in real terms. Current technology is assumed in terms of well productivity, success rates, and drilling costs.

A total of about 1,200 to 1,400 Tcf of gas resource in the U.S. and Canada is available at gas prices between $3.50 and $4.00 per MMBtu.

This analysis shows that a large component of the technically recoverable resource is economic at relatively low wellhead prices. This supply curve assessment is conservative in that it assumes no improvement in drilling and completion technology and cost reduction, while in fact, large improvements in these areas have been made historically and are expected in the future.

Exhibit B 3 : U.S. and Canada Natural Gas Supply Curves

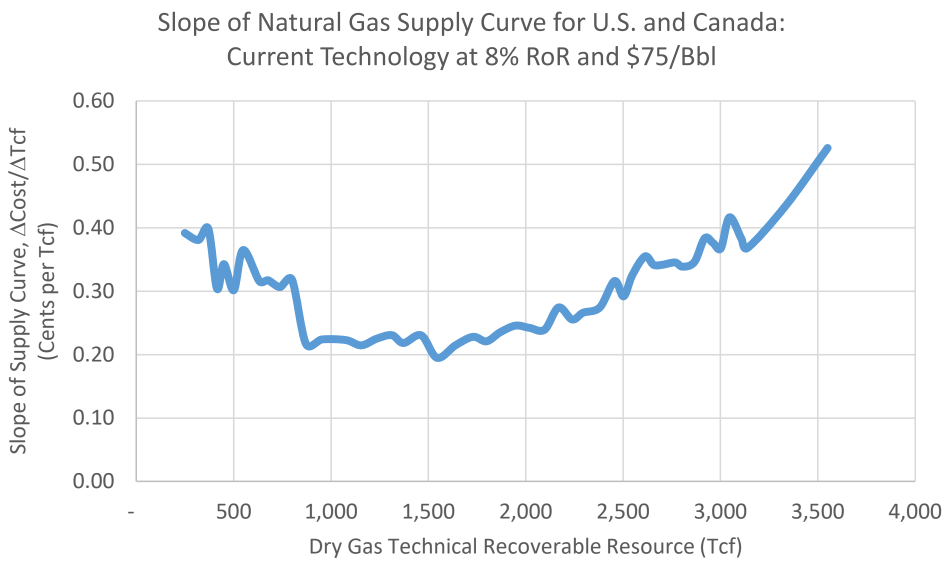


Source: ICF

A natural gas supply curve can also be described in terms of its slope.

Exhibit B 4 shows the slope of the Lower 48 plus Canada curve in cents per Tcf. In the forecast cases to be shown later in this report, the U.S. is projected to develop approximately 847 to 945 Tcf of natural gas resources through 2040 and Canada to develop another 166 to 176 Tcf. Combining the two countries, depletion for the U.S. and Canada will be in the range of 1,013 to 1,121 Tcf. This means that incremental development of one Tcf of natural through 2040 would have a "depletion effect on price" of natural gas of 0.2 to 0.4 cents (assuming no upstream technological advances to increase available volumes and to decrease costs) during the forecast period. As is explained below, the depletion effect on price is only one of several factors that need to be considered when estimating the price impacts of LNG exports or any other change to demand.

Exhibit B 4 : Slope of U.S. and Canada Natural Gas Supply Curve



Source: ICF

Representation of Future Upstream Technology Improvements

Technological advances have played a big role in increasing the natural gas resource base in the last few years and in reducing its costs. As discussed below, it is reasonable to expect that similar kinds of upstream technology improvements will occur in the future and that those advances will make more low-cost natural gas available than what is indicated by the "current technology" gas supply curves.31

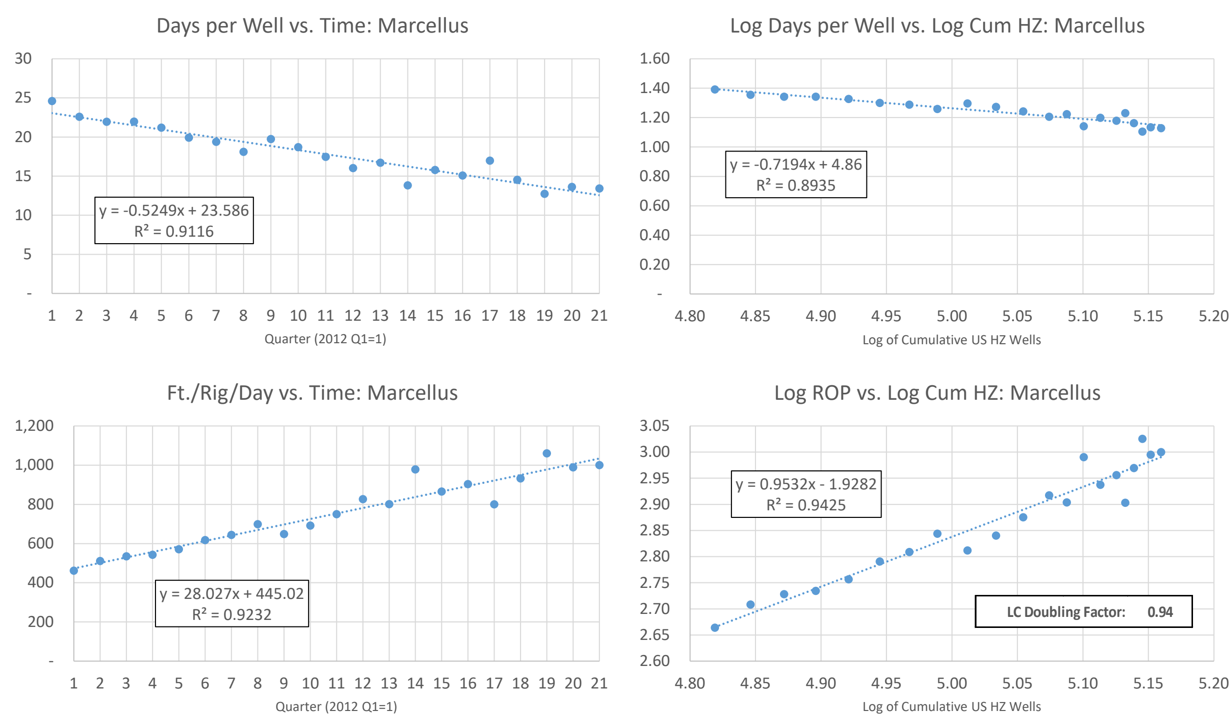
Technology advances in natural gas development in recent years have been related to the drilling of longer horizontal laterals, expanding the number and effectiveness of stimulation stages, use of advanced proppants and fluids, and the customization of fracture treatments based upon real-time micro-seismic and other monitoring. Lateral lengths and the number of stimulation stages are increasing in most plays and the amount of proppant used in each stimulation has generally gone up. These changes to well designs can increase the cost per well over prior configurations. The percentage increase in gas and liquids recovery is much greater than the percentage increase in cost, however, resulting in lower costs per unit of reserve additions.

[31] This discussion of upstream technology effects has been adapted from prior report written by ICF including "Impact of LNG Exports on the U.S. Economy: A Brief Update," Prepared for API, September 2017. See http://www.api.org/news-policy-and-issues/lng-exports/impact-of-lng-exports-on-the-us-economy

Technology Advances in Rig Efficiency

ICF expects that drilling costs (as measured in real dollars per foot of measured well depth) will continue to be reduced largely due to increased efficiency and the higher rate of penetration (feet drilled per rig per day). ICF's modeling of drilling activity and costs considers how changes in oil and gas prices and activity levels can influence the unit cost of drilling, stimulation (hydraulic fracturing) services and other equipment and oil field services used to develop oil and gas. Thus, higher oil and gas prices translate into higher factor costs, which partially dampens the ability of higher commodity prices to lead to increase drilling activity and more production. As illustrated in the upper-left-hand chart in Exhibit B 5, the number of rig days required to drill a well has fallen steadily in many plays. This chart shows that Marcellus gas shale wells drilled in early 2012 required 24.6 rig days but that by early 2017 that had fallen to 13.4 days. Because lateral lengths increased over this time, total footage per well was going up (from 11,300 to 13,400 feet for Marcellus wells) over this period. As shown in the lower-left-hand chart in Exhibit B 5 this meant that footage drilled per rig per day (RoP) was going up quickly. For the Marcellus play RoP went from 461 feet in per day early 2012 to 1,000 feet per day in early 2017. Rig day rates and other service industry costs have declined since 2013 due to reduced drilling activity brought on by lower oil and gas prices and lack of demand for rigs. Improved technology and efficiency in combination with lower rig rates and other service costs have allowed industry to develop economic resources despite low oil and gas prices.

Exhibit B 5 : Recent Trends in Rig-Days Required to Drill a Well: Marcellus Shale (first quarter 2012 to first quarter 2017)



Source: ICF

To estimate the contributions of changing technologies ICF employs the "learning curve" concept used in several industries. The "learning curve" describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period-of-time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures.

The two right-hand charts in Exhibit B 5 show how learning curves for rig efficiency can be estimated. The horizontal axis of both charts is the base 10 log of the cumulative number of horizontal multi-stage hydraulically fractured wells drilled in the U.S. and Canada. The y-axis of the upper-right-hand chart is the base 10 log of the rig days needed per well. The y-axis of the lower-right-hand chart is the base 10 log of RoP measured in feet per day per rig. The log-log least-square regression coefficients need to be converted[32] to get the learning curve doubling factor of -0.39 for rig days per well and 0.94 for RoP. What this mean is that rig days per well go down by 39% for each doubling of cumulative horizontal multi-stage hydraulically fractured wells and that RoP goes up by 94% for each doubling.

The rig efficiency learning curve factors shown for the Marcellus are some of the largest among North American gas shale and tight oil plays. The average learning curve doubling factor for rig efficiency among all horizontal multi-stage hydraulically fractured plays is -0.13 when measured as rig days per well and 0.44 when measured as RoP.

Technology Advances in EUR per Well or EUR per 1,000 feet of Lateral

ICF also used the learning curve concept to analyze trends in estimated ultimate recovery (EUR) per well over time to determine how well recoveries are affected by well design and other technology factors and how average EURs are affected by changes in mix of well locations within a play. The most technologically immature resources, wherein technological advances are among the fastest, include gas shales and tight oil developed using horizontal multi-stage hydraulically fractured wells. As with the rig efficiency calculations shown above, when looking at EURs for horizontal gas shale or tight oil wells, ICF estimates what the percent change in EUR is for each doubling of the cumulative North American horizontal multi-stage fracked wells. We first measure EUR on a per-well basis to look at total effects and then EUR per 1,000 feet of lateral to separate out the effect of increasing lateral length. This statistical analysis is done using a “stacked regression” wherein each geographic part of the play is treated separately to determine the regression intercepts, but all areas are looked at together to estimate a single regression coefficient (representing technological improvements) for the play.

We find that the total technology learning curve shows roughly 30 percent improvement in EUR per well for each doubling of cumulative horizontal multistage fracked wells. When we take out the effect of lateral lengths by fitting EUR per 1,000 feet of lateral rather than EUR per well, we find the learning curve effect is roughly 20 percent per doubling of cumulative wells. In other words, about one-third of the observed total 30% improvement in EUR per well doubling factor is due to increase lateral lengths and about two-thirds are due to other technologies such as better selection of well locations, denser spacing of frack stages, improved fracture materials and designs, and so on.

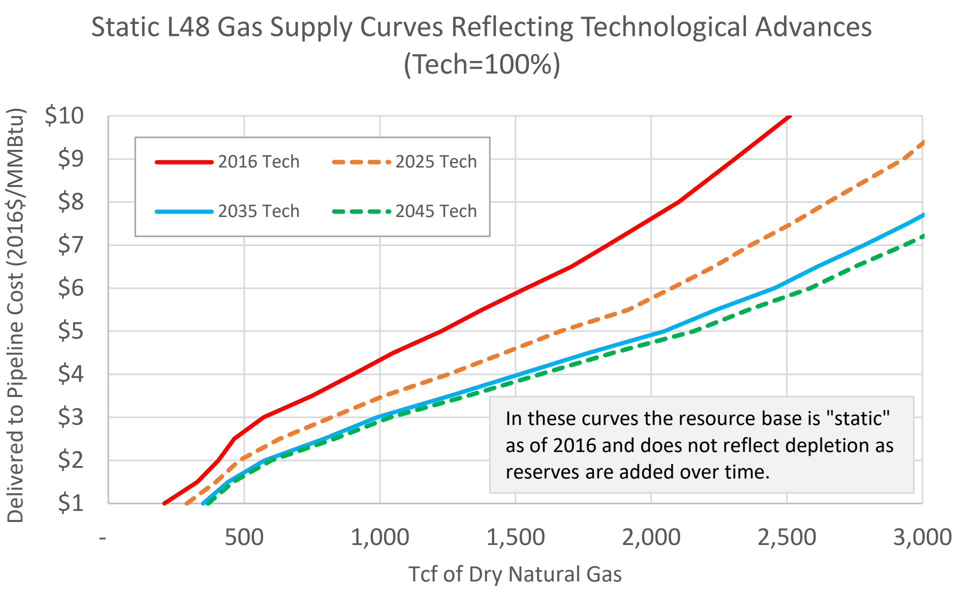
The Effect of Technology Advances on the Gas Supply Curves

The net effect of assuming that these technology trends continue in the future is to increase the amount of natural gas that is available at any given price. In other words, the gas supply curve “shifts down and to the right.” This effect is illustrated in Exhibit B 6 which shows the Lower 48 natural gas supply curve for 2016 technology as a red line. The other lines in the chart represent the same (undepleted) resource that existed as of the beginning of 2016 but as it could be developed under the improved technologies assumed to exist in 2025 (dashed orange line), 2035 (blue line) and 2045 (dashed green line). ICF estimates that by extrapolating recent technological advances into the future, the amount of gas in the Lower 48 that are economic at $5/MMBtu would

[32] Doubling factor = 2^C-1 where C is the regression slope coefficient.

increase from 1,225 Tcf to 2,160 Tcf, a 76% increase. The improved technologies include for gas shales and tight oil the EUR and rig efficiency improvements discussed above. Conventional resources and coalbed methane are assumed to be much more mature technologies with little future improvement (on average one-half of percent per year net reduction in cost per unit of production)

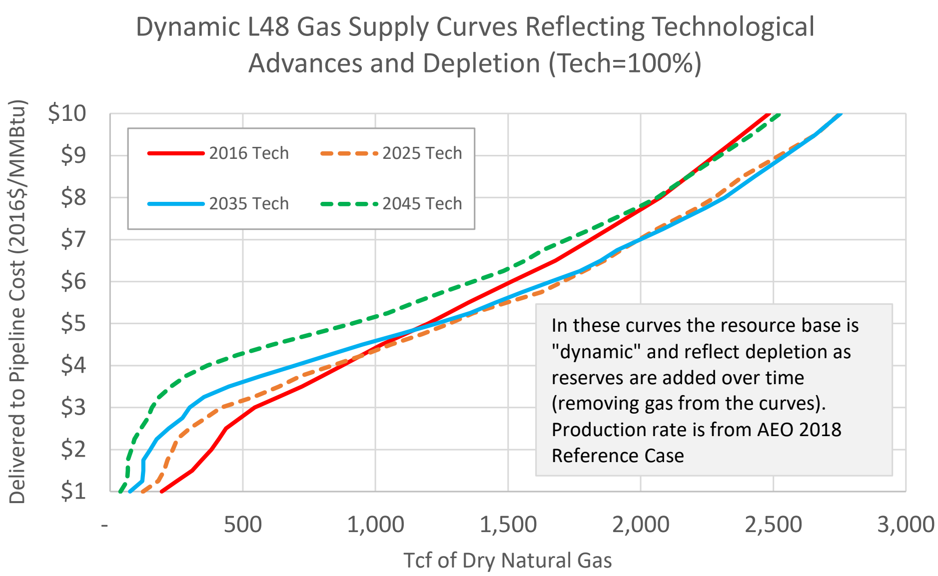
Exhibit B 6 : Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (static curves representing undepleted resource base as of 2016)



Source: ICF

The effect of technology advances on gas supply curves are shown in another way in Exhibit B 7. Here the Lower 48 curves are adjusted over time to show the effects of depletion based on reserve additions that would be expected to occur under the 2018 AEO Reference Case (that is for instance, cumulative reserve additions of 974 Tcf by 2040). In Exhibit B 7 the dashed orange line, for example, is the supply curve that would exist in the year 2025 if reserve additions consistent with the 2018 AEO Reference Case production forecast were to occur between now and then and that the technology advances assumed by ICF were to take place through 2025. Since technology adds resources faster than production takes place (consistent with the recent assessments made by ICF, Potential Gas Committee (PGC) and EIA), the upper part of the curve moves to the right from 2016 to 2025 and again from 2025 to 2035. However, because the technology advances for unconventional gas resource are represented by learning curves that flatten out over time, the upper part of the curve for 2045 moves to the left relative to the 2035 curve. Another important observation from these curves is that the lower-cost parts of the supply curve deplete more quickly than the high-cost portions as producers concentrate on low-cost (high profit) segments and will not exploit resources that have costs higher than prevailing market prices. Even so, the amount of natural gas available in these curves at $5.00 per MMBtu increases through 2035 and even by 2045 the curve still has approximately 1,000 Tcf at that price.

Exhibit B 7 : Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (dynamic curves showing effects of depletion through time)



Source: ICF

The development of supply curves and the projection of how those curves will change through time is inherently uncertain given that:

- Our understanding of the geology of the natural gas and tight oil resource base changes as known plays are developed, their geographic boundaries are expanded, and new plays are discovered and enter development,
- The technologies used to develop those resources evolve, thus, improving their performance and changing the unit cost of equipment and services employed in oil and gas development,
- The market for energy evolves, thus, changing the volumes produced and prices of natural gas and competing fossil and renewable resources.

This means that the estimates provided here for the market impacts of any given amount of LNG exports could be proven in time to be overstated or understated. In reviewing the trends of economic impact studies performed over the last serval years with regard to U.S. LNG exports, we see that the more recent studies show lower impacts in terms of cents per MMBtu of natural gas price increases per 1 Bcfd of exports compared to the older studies. This indicates that the forecasts have tended to:

- Understate natural gas supply robustness (that is, upstream technologies have evolved faster than expected and reduced the cost of developing natural gas more than expected) and
- Understate energy market forces that have reduced the domestic needs for natural gas (e.g., slower overall growth in demand for all energy and higher market penetration of renewables).

If these apparent forecasting biases still exists, then the price impacts for a given volume of LNG exports shown in this and similar economic impact reports will turn out lower.

ICF Resource Base Estimates

ICF has assessed conventional and unconventional North American oil and gas resources and resource economics. ICF's analysis is bolstered by the extensive work we have done to evaluate shale gas, tight gas, and coalbed methane in the U.S. and Canada using engineering and geology-based geographic information system

(GIS) approaches. This highly granular modeling includes the analysis of all known major North American unconventional gas plays and the active tight oil plays. Resource assessments are derived either from credible public sources or are generated in-house using ICF's GIS-based models.

The following resource categories have been evaluated:

Proven reserves – defined as the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology.

Reserve appreciation – defined as the quantities of oil and gas that are expected to be proven in the future through additional drilling in existing conventional fields. ICF's approach to assessing reserve appreciation has been documented in a report for the National Petroleum Council.[33]

Enhanced oil recovery (EOR) – defined as the remaining recoverable oil volumes related to tertiary oil recovery operations, primarily CO_2 EOR**.**

New fields or undiscovered conventional fields – defined as future new conventional field discoveries. Conventional fields are those with higher permeability reservoirs, typically with distinct oil, gas, and water contacts. Undiscovered conventional fields are assessed by drilling depth interval, water depth, and field size class.

Shale gas and tight oil – **Shale gas** volumes are recoverable volumes from unconventional gas-prone shale reservoir plays in which the source and reservoir are the same (self-sourced) and are developed through hydraulic fracturing. **Tight oil** plays are shale, tight carbonate, or tight sandstone plays that are dominated by oil and associated gas and are developed by hydraulic fracturing.

Tight gas sand – defined as the remaining recoverable volumes of gas and condensate from future development of very low-permeability sandstones.

Coalbed methane – defined as the remaining recoverable volumes of gas from the development of coal seams. Exhibit B 8 summarizes the current ICF gas and crude oil assessments for the U.S. and Canada.

Resources shown are "technically recoverable resources." This is defined as the volume of oil or gas that could technically be recovered through vertical or horizontal wells under existing technology and stated well spacing assumptions without regard to price using current technology. The current assessment temporal basis is the start of 2016. The current assessment is 3,693 Tcf. As shown in the exhibit below, almost 65 percent of the gas resources is from shale gas and tight oil plays. Large portion of the resources is in the Marcellus, Utica, and Haynesville shale gas plays. The largest tight oil gas resource is in the Permian basin. It accounts for almost 30% of the gas resource from tight oil plays.

[33] This methodology for estimating growth in old fields was first performed as part of the 2003 NPC study of natural gas and has been updated several times since then. For details of methodology see U.S. National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," http://www.npc.org/

Exhibit B 8 : ICF North America Technically Recoverable Oil and Gas Resource Base Assessment (current technology)

(Tcf of Dry Total Gas and Billion Barrels of Liquids as of 2016; Excludes Canadian and U.S. Oil Sands)

	Total Gas	Crude and Cond.
Lower 48	**Tcf**	**Bn. Bbls**
Proved reserves	320	33
Reserve appreciation and low Btu	161	17
Stranded frontier	0	0
Enhanced oil recovery	0	42
New fields	361	71
Shale gas and condensate	2,133	86
Tight oil	252	78
Tight gas	401	7
Coalbed methane	65	0
Lower 48 Total	**3,693**	**334**
Canada		
Proved reserves	71	5
Reserve appreciation and low Btu	23	3
Stranded frontier	40	0
Enhanced oil recovery	0	3
New fields	205	12
Shale gas and condensate	618	14
Tight oil	26	10
Tight gas (with conventional)	0	0
Coalbed methane	75	0
Canada Total	**1,058**	**46**
Lower-48 and Canada Total	**5,751**	**380**

Sources: ICF, EIA (proved reserves)

Resource Base Estimate Comparisons

The ICF natural gas resource base assessment for the U.S. Lower 48 states is historically higher than many other sources, primarily due to our bottom-up assessment approach and the inclusion of resource categories (including infill wells) that are excluded in other analyses. These additional resources in the ICF assessments tend to be in the lower-quality fringes of currently active play areas or are associated with lower-productivity infill wells that may eventually be drilled between current adjacent well locations. Therefore, the additional resources are often higher cost and are added to the upper end of the natural gas supply curves. Such resources may eventually be exploited if natural gas prices increase substantially or if upstream technological advances improve well recovery and decrease costs enough to make these resources economic. The inclusion of these fringe and infill resources into the ICF forecasts has little effect on results in the near term because current drilling and the drilling forecast for the next 20 years will be in the "core" and "near-core" areas. Therefore, removing the fringe/infill resources will not have a great effect on model runs projecting market results through 2045.

There are several other reasons for the magnitude of the differences:

- More plays are included. ICF includes all major shale plays that have significant activity. Although in recent years, EIA has published resources for most major plays, the ICF analysis is more complete. Examples of plays assessed by ICF but not by EIA are the Paradox Basin shales and Gulf Coast Bossier. ICF also has a more comprehensive evaluation of tight oil and associated gas.

- ICF includes the entire shale play, including the oil portion. Several plays such as the Eagle Ford have large liquids areas.
- ICF employs a bottom-up engineering evaluation of gas-in-place (GIP) and original oil-in-place (OOIP). Assessments based upon in-place resources are more comprehensive.
- ICF looks at infill drilling (or new technologies that can substitute for infill wells) that increase the volume of reservoir contacted. Infill drilling impacts are critical when evaluating unconventional gas. ICF shale resources are based upon the first level of infill drilling, with primary spacing based upon current practices. In other words, if the current practice is 120 acres and 1,000 feet spacing between horizontal well laterals, our assessment assumes an ultimate spacing can be (if justified by economics) 60 acres and 500 feet spacing between laterals.
- For conventional new fields, ICF includes areas of the Outer Continental Shelf (OCS) that are currently off-limits, such as the Atlantic and Pacific OCS.
- ICF evaluates all hydrocarbons at the same time (i.e., dry gas, NGLs, and crude and condensate). While not affecting gas volumes, it provides a comprehensive assessment.
- ICF employs an explicit risking algorithm based upon the proximity to nearby production and factors such as thermal maturity or thickness.

It should also be noted that ICF volumes of technically recoverable resources include large volumes of currently uneconomic resources on the fringes of the major plays, although ICF did not include shale gas reservoirs with a net thickness of less than 50 feet.

ICF has evaluated the United States Geological Survey (USGS) Marcellus shale gas assessment to determine the factors that contribute to their low assessment. We concluded that USGS used incorrect well recovery assumptions that are far lower than what is currently being seen in the play. In addition, the well spacing assumptions differ from current practices. EIA is using a modified version of the USGS Marcellus that is still low compared to ICF evaluation. The relatively high ICF Barnett Shale assessment is the result of our including a large fringe area of low-quality resource. The great majority of this fringe area is uneconomic, so the comparison is not for an equivalent play area.

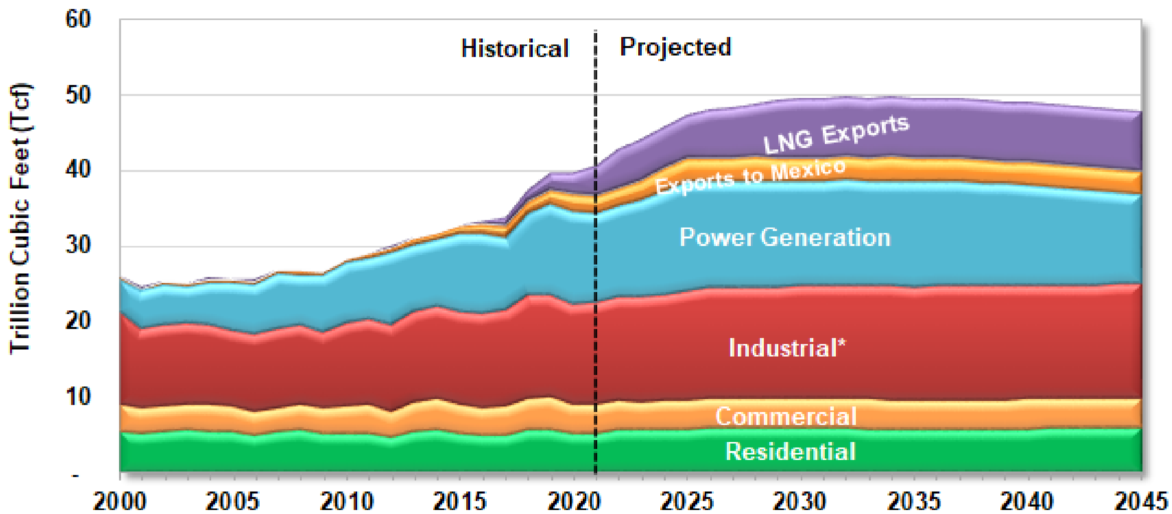
The ICF assessment of tight oil associated gas is much higher than that of other assessments. The difference reflects our inclusion of more plays and entire play areas. It also reflects our methodology, which generally assesses recoverable resources through determination of resource in-place, with an assumed recovery factor that is calibrated to existing well recoveries. Our assessment of several plays in Oklahoma is also based upon a new data-intensive method using GIS and well level recovery estimates, and that method typically results in higher assessments.

U.S. and Canadian Natural Gas Demand Trends

Natural gas exports (LNG and Mexico) are key drivers for near-term and long-term demand growth and account for about half of the overall demand growth over the next 25 years. Natural gas demand for power generation is expected to increase in the near term due to additional gas power plant builds and lower coal generation. In the Long run, power generation gas demand is expected to decline due to higher renewable penetration, state level initiatives to pursue mandatory renewable portfolio standards and state/federal regulations that drive higher energy efficiency and incentivize energy storage. Natural gas demand in industrial sector is expected be up slightly in the long run as gas-intensive end uses such as petrochemicals and fertilizers. In the transportation sector (compressed natural gas and LNG used in vehicles and off-road equipment), ICF expects significant penetration of electric vehicle technologies (both on road and off road) starting 2030.

Exhibit B 9 shows ICF’s U.S. and Canadian consumption forecast by sector. Under the base case, ICF assumes that 12 North American LNG export terminals will be built and/or expanded: Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, Elba Island, Golden Pass, LNG Canada, Woodfibre, Calcasieu Pass, Costa Azul, and Driftwood LNG.

Exhibit B 9 : U.S. and Canadian Gas Consumption by Sector and Exports



* Includes pipeline fuel and lease & plant
Source: ICF GMM® Q2 2022

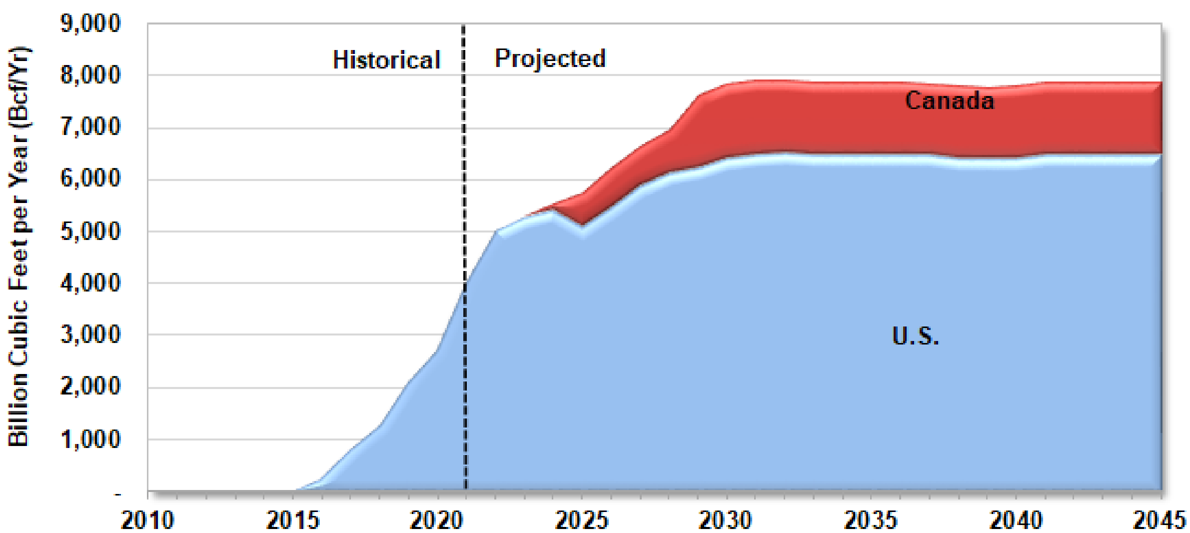
Feed gas deliveries for U.S. and Canadian LNG exports are projected to reach 7.8 Tcf per year (21.6 Bcfd) by 2045, with volumes from the Gulf Coast expected to reach 6.4 Tcf per year (17.8 Bcfd), based on ICF's review of projects approved by the Federal Energy Regulatory Commission and the Department of Energy. Incremental power sector gas use between 2022 and 2045 is expected to decline over the period, with renewable power generation expected to increase significantly over time. Gas use for power generation will decrease from about 11.9 Tcf (32.63 Bcfd) in 2022 to 11.8 Tcf per year (32.38 Bcfd) by 2045.
Several factors the growth of gas demand for power generation in the near term. Currently, about 600 gigawatts (GW) of existing gas-fired generating capacity is available in the U.S. and Canada. Much of that capacity is underutilized and readily available to satisfy incremental electric load growth. U.S. electric load growth is based on the latest available projections from ISOs as well as forecasts from NERC. Electricity demand is projected to average 0.69% per year from 2022-2045 across the U.S., which is driven by the ISO's expected levels of demand change, including the impacts of electrification of the transportation and other sectors, as well as offsetting changes in energy efficiency adoption. ICF assumes that by 2023, consistent with Moody's estimate of economic impacts, there will be a full recovery to the forecasted demand to pre-pandemic levels. Updates to firm generation capacity additions and retirements based on announcements are as of April 2022. The ICF Base Case includes regional carbon control programs in California and for the Regional Greenhouse Gas Initiative (RGGI) states, as well as a probability-weighted national CO2 charge that is representative of federal carbon policies that may take effect between now and 2050. ICF's Base Case also reflects EPA rules governing power plants, including the Mercury & Air Toxics Standards Rule (MATS), the Cross-State Air Pollution Rule (CSAPR), and rules governing water intake structures under Clean Water Act 316(b), and coal combustion residuals (CCR, or ash).

Growth in gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is driven by both population growth and efficiency improvements. Energy efficiency gains lead to lower per-customer gas consumption, thus somewhat offsetting gas demand growth in the residential and commercial sectors, which lead to lower per-customer gas consumption. Gas use by natural gas vehicles (NGVs) is included in the commercial sector. The Base Case assumes that the growth of NGVs is primarily in fleet vehicles (e.g., urban buses), and vehicular gas consumption is not a major contributor to total demand growth. In addition, pipeline exports to Mexico are expected to increase to over 2.8 Tcf (7.9 Bcfd) by 2045, up from 2.3 Tcf (6.3 Bcfd) in 2022.

LNG Export Trends

With an increased reliance on US LNG exports by the European Union in order to move away from Russian supplies, the U.S. export facilities are currently running at full capacity. Europe is seeking an additional 2-15 Bcfd of exports demand from across the globe. There is about 14.5 Bcfd of U.S. LNG export capacity currently in-service with another 2.5 Bcfd planned by 2025. The U.S. has an additional 30 Bcfd of export capacity that is FERC approved, which is double the potential additional demand required by Europe. However, ICF's Q2 2022 base case didn't include any additional greenfield facilities since these projects were missing long-term contracting and final investment decisions (FIDs). Based on our assessment of world LNG demand and other international sources of LNG supply, the Base Case of this study assumes that the U.S. and Canadian LNG exports reach 7.8 Tcf per year (21.6 Bcfd) by 2045. Global LNG prices are heavily influenced by oil prices. Given the current global economic climate and high oil price environment, U.S. and Canadian export volumes are projected to be about 5 Tcf per year (13.7 Bcfd) in 2022 (see exhibit below).

Exhibit B 10 : U.S. and Canadian Base Case LNG Export Assumptions

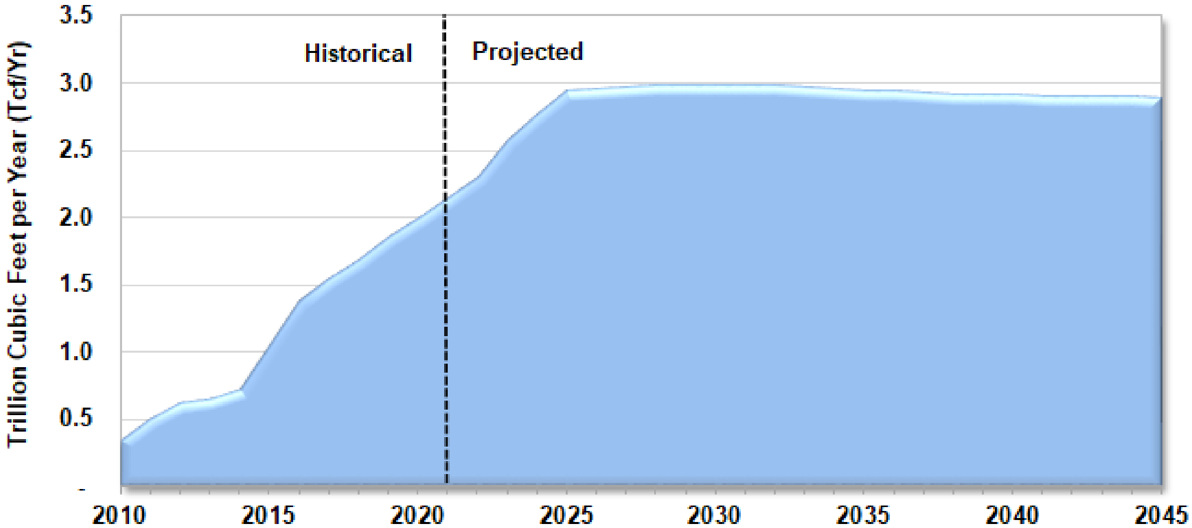


Source: ICF GMM® Q2 2022

Pipeline Exports to Mexico

Mexico's demand for natural gas continues to rise, while its domestic production has been declining. Since 2015, Mexico's imports of U.S. gas have undergone a 118% increase, reaching 6.3 Bcfd in 2022. As Mexico continues to add gas-fired generation and sponsor new pipelines from the U.S., exports will continue to grow, reaching 8.2 Bcfd by 2030 and then level off.

Exhibit B 11 : Base Case Exports to Mexico Assumptions



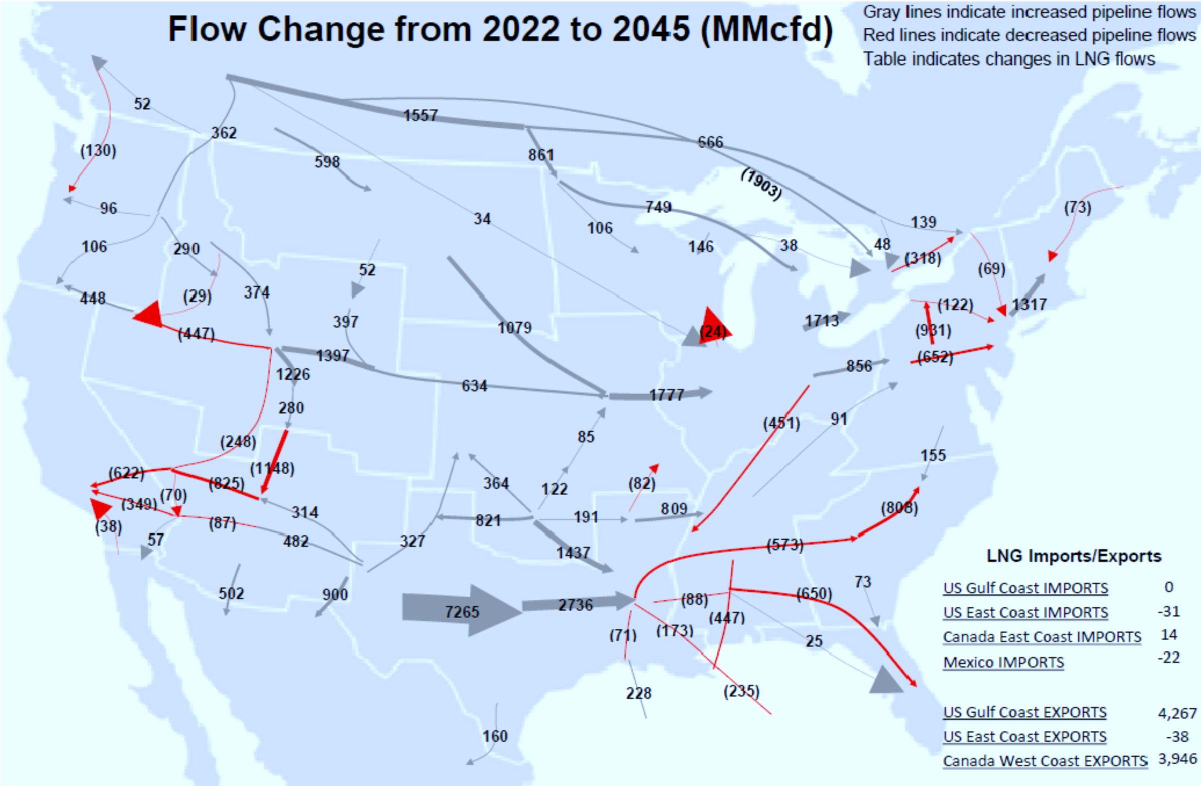
Source: ICF GMM® Q2 2022

U.S. and Canadian Natural Gas Midstream Infrastructure Trends

As regional gas supply and demand continue to shift over time, there will likely be significant changes in interregional pipeline flows. Exhibit B 12 shows the projected changes in interregional pipeline flows from 2022 to 2045 in the Base Case. The map shows the United States divided into regions. The arrows show the changes in gas flows over the pipeline corridors between the regions between the years 2022 and 2045, where the gray arrows indicate increases in flows and red arrows indicate decreases.

Exhibit B 12 illustrates how gas supply developments will drive major changes in U.S. and Canadian gas flows. Marcellus gas production growth continues to reverse flows, pushing gas toward the west and south. New developments in Midcontinent unconventional plays will increasingly flow to the Gulf Coast region. Rocky Mountain production will increasingly move westward and serve local demand. Longer term Permian production will primarily be directed to the Gulf Coast. Eastward flows out of Western Canada will continue to remain relatively low as incremental gas supplies are consumed locally or exported off of the West Coast of Canada.

Exhibit B 12 : Projected Change in Interregional Pipeline Flows

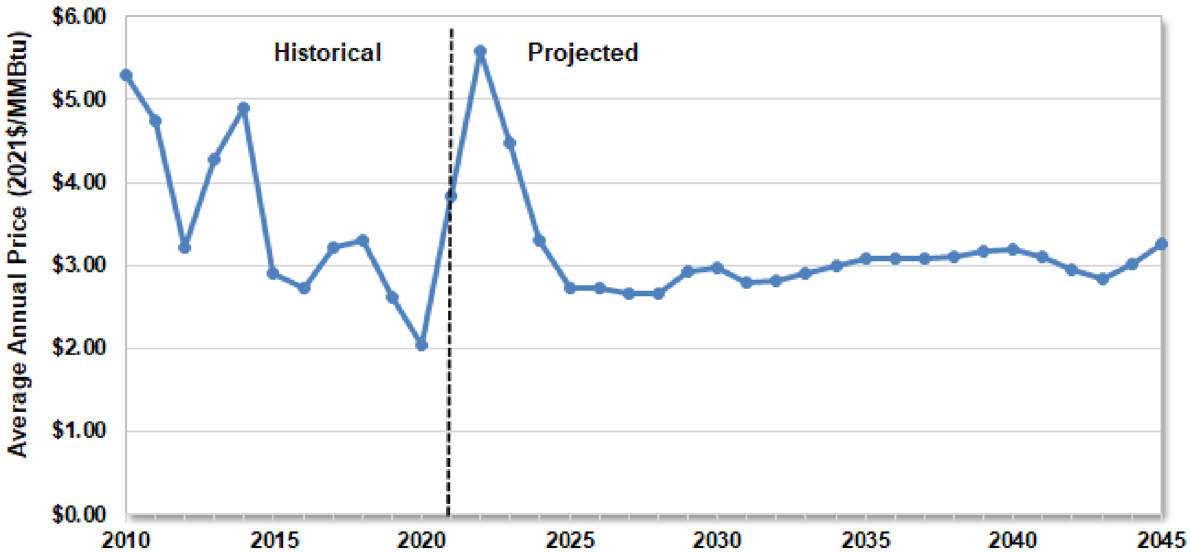


Source: ICF GMM® Q2 2022

Natural Gas Price Trends

Natural gas prices at the major market hubs in North America are forecasted to be higher in 2022 than they were in 2021 due to a significant rise in LNG exports demand, low levels of natural gas in storage, production gains slower than expected and the fluctuating weather. The Henry Hub price is projected to average $5.57/MMBtu (in real 2021$) in 2022 compared to $3.82/MMBtu in 2021. The average annual price at Henry Hub is projected to be $4.47/MMBtu in 2023, $3.29/MMBtu in 2024 and $2.73/MMBtu in 2025 (in real 2021$), under normal weather conditions, as natural gas markets rebalance with increased drilling and production activities. The natural gas price at Henry Hub is projected to average under $3.2/MMBtu in real 2021$ over the next 25 years and are never expected to be below the 2020 prices under normal weather conditions.
Gas prices throughout the U.S. are expected to remain moderate, as shown in Exhibit B 13.

Exhibit B 13 : GMM Average Annual Prices for Henry Hub

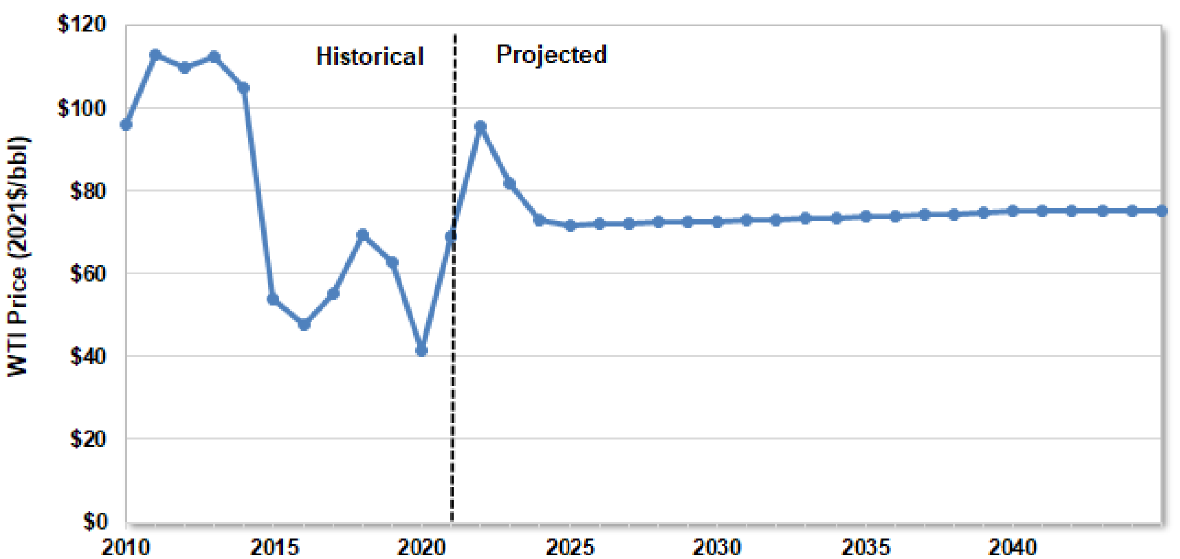


Source: ICF GMM® Q2 2022

Oil Price Trends

ICF's crude oil price forecast uses futures prices for 2022 and a blend of futures and our fundamental forecast for 2022-2025. For the long-term, ICF assumes an equilibrium marginal production cost of $70/Bbl (in real 2021$). Oil prices are higher in 2022 compared to last 7 years. European Union continues to push for a ban on Russian oil imports. This would tighten global oil supply amid expectation of higher demand from easing of China's COVID lockdowns.

Exhibit B 14 : ICF Oil Price Assumptions



Source: ICF GMM® Q2 2022

Appendix C: ICF's Gas Market Model (GMM)

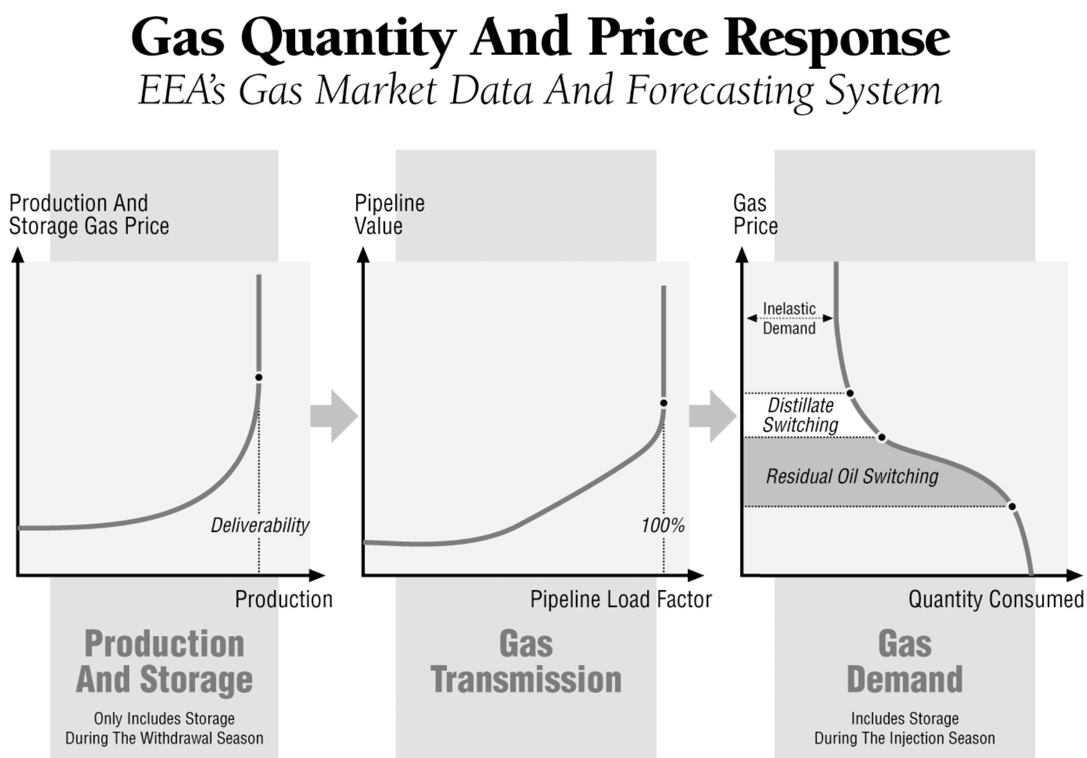
ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid-1990s to provide forecasts of the U.S. and Canada natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. Subsequently, GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients and advisory councils, including Interstate Natural Gas Association of America (INGAA), which has relied on the GMM for multiple studies over the past ten years. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003, and the 2010 Natural Gas Market Review for the Ontario Energy Board.

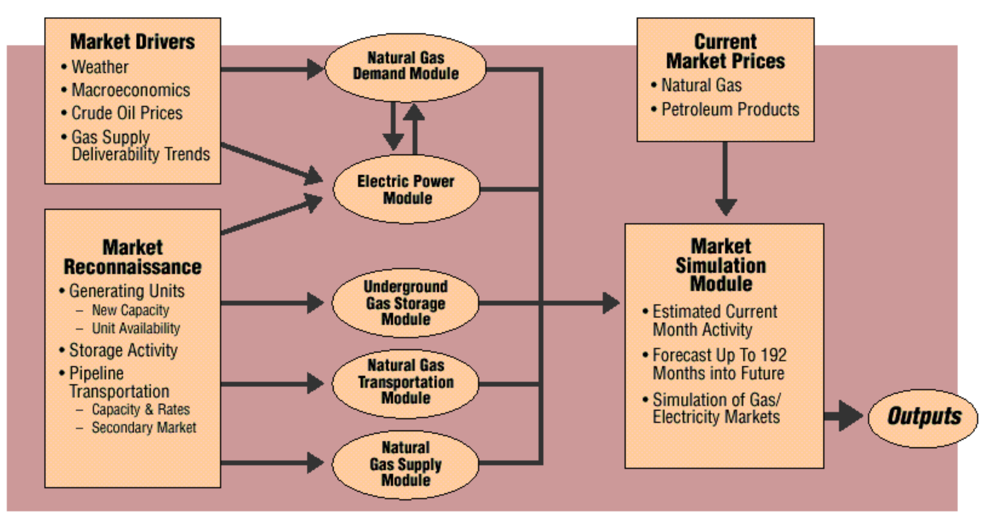
GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by scenario. Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Exhibit C 1). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, ICF does significant back-casting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Exhibit C 1: ICF's Gas Market Data and Forecasting System



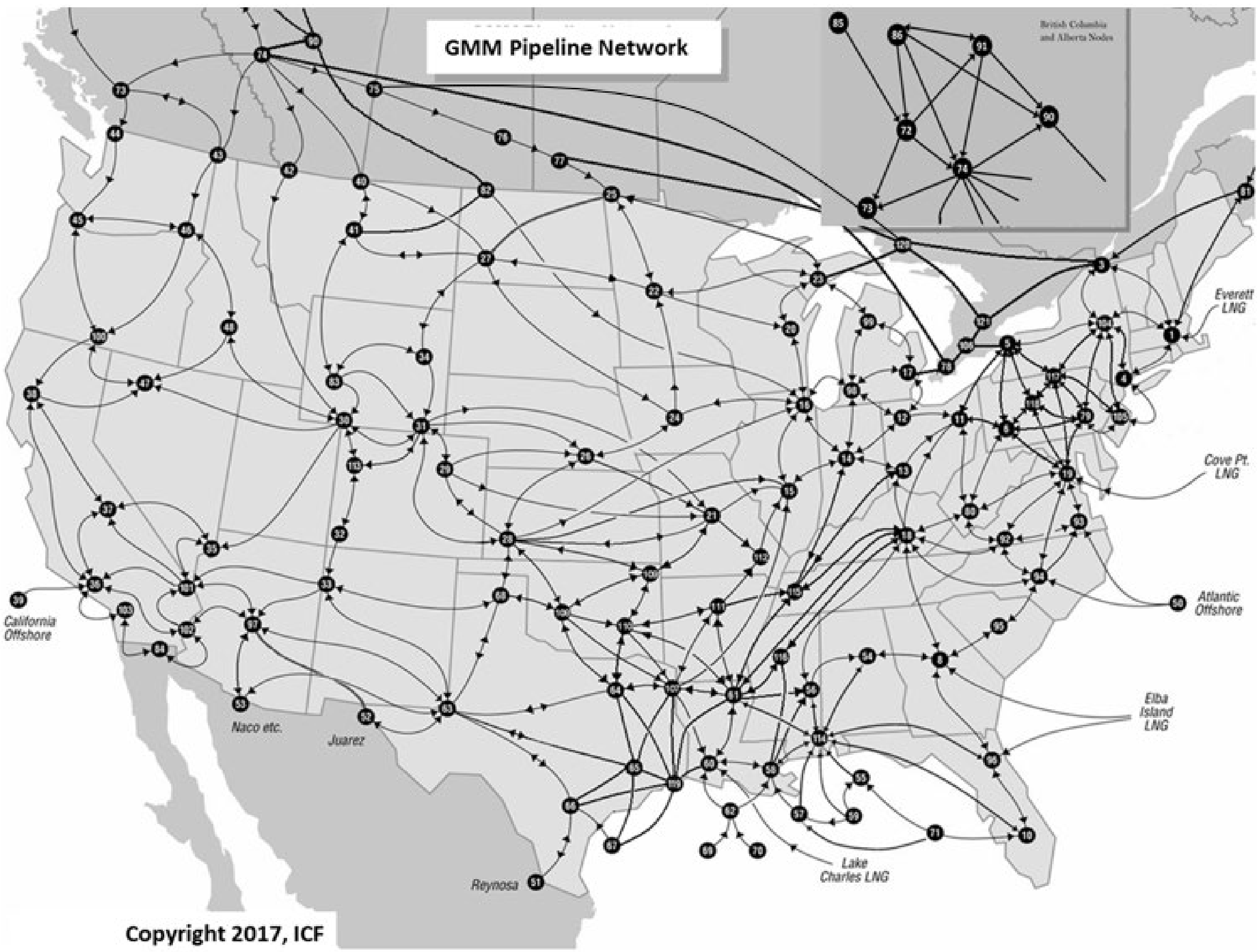
There are nine different components of GMM, as shown in Exhibit C 2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

Exhibit C 2 : GMM Components



The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Exhibit C 3. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import and export levels. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

Exhibit C 3: GMM Transmission Network



Appendix D: Ontario Market Based Storage Contract Database

The market-based storage deliverability value analysis in section 3 of this report is based on an analysis of storage contract data developed by combining multiple data sources. These data sources include:

1) The Enbridge Gas index of storage customers https://www.enbridgegas.com/-/media/Extranet-Pages/Storage-and-transportation/operational-information/Index-of-customers/Storage_Report.ashx?rev=f1cbc47f701341bc98c29f353995a70d&hash=3C14D646A2882C749640BD536C2EF7F8
2) The Enbridge Gas's Semi-Annual Storage Report (STAR) for the period from March 1, 2021 to August 31, 2021: STAR storage report for October 2021.xlsx (enbridgegas.com)

The STAR report provides unit rates and total revenue for each storage contract, along with the customer's name. ICF used this data to calculate the capacity associated with each contract. The Index of Customer database provides space and deliverability information for each storage contract, along with the customer's name. ICF combined the records from these two public reports by matching customer names and contract capacity in order to develop a database of storage contracts with price, space, and deliverability.

ICF also included in the regression analysis the prices, space, and deliverability data from third party storage offers provided to Enbridge Gas in response to RFPs for storage services. These records are confidential in nature and not included in this report.

Appendix E: Incremental Value of Storage Relative to Gas Purchases at Dawn

Gas purchases at Dawn are not a perfect substitute for holding natural gas storage capacity. Storage capacity provides additional value on a daily basis relative to purchases at Dawn in several different areas. These include:

1) Contribution of Storage Deliverability to Design Day Capacity Requirements. Storage deliverability provides a direct contribution to design day system capacity requirements. In the Gas Supply Planning model analysis, changes in storage capacity are addressed through incremental purchases at Dawn. However, purchases at Dawn do not have the degree of reliability provided by storage deliverability. The different in reliability provides significant economic benefit to the use of incremental storage that is not captured in the Gas Supply Planning model analysis.

2) Value of Daily Gas Supply Purchasing Flexibility. Storage capacity allows for a more flexible gas purchasing approach that allows the utility to shift purchases on high priced days to purchases on lower priced days. This provides a direct economic benefit to the use of storage that is not captured in the use of storage to address aggregate excess requirements, or through the use of monthly average prices.

Value of Storage Deliverability

A change in the use of market-based storage to service bundled service customers would change the reliability of natural gas supply during peak periods. In order to assess the value of this change, ICF looked at the cost of replacing lost deliverability from natural gas storage with delivered services. Based on our assessment of the market, the cost of very high deliverability market-based storage at Dawn likely would set the initial cost of delivered services. Using the ICF assessment of the likely cost of deliverability associated with high deliverability storage ICF estimated an initial cost of delivered services at $3.72/GJ/Day for 10 days of delivered services. This is reflected in the storage price analysis described below. In this analysis, a change in storage capacity of one PJ would lead to a reduction in storage deliverability of 0.012 PJ. The cost of replacement deliverability is estimated to be $0.41 per GJ of storage capacity per year. [34],[35]

The storage price analysis is based on historical data on market-based storage contracts from the Enbridge Gas storage STAR Report[36] and the Enbridge Gas Storage Holders Index of Customers[37] to create a database of market-based storage contracts with capacity, deliverability, and rates. ICF also included responses to recent Enbridge Gas RFPs for market-based storage in the storage contract value database. ICF used the integrated storage contract value database to conduct a regression analysis of the value of storage based on the space and deliverability characteristics in each contract.[38] The results of the regression analysis are shown in Exhibit E 1. The contract database used in this analysis is included in Appendix D to this report.

Contribution from Short Term Price Volatility on Storage Value

Incremental storage capacity above the level indicated by the Aggregate Excess methodology also increases the utility's ability to optimize purchase patterns, including reducing purchases at Dawn at the highest priced days and increasing purchases at Dawn on days with lower prices. Over the last five years (2018 – 2022), the highest priced day in January has averaged about US$1.71 per MMBtu higher than the average January price. The lowest price day in January has averaged about $0.48 per MMBtu below than the average January price. Hence the ability to shift purchases from the highest cost day to the lowest cost day in January would reduce gas purchase costs by $2.19 per MMBtu. Achieving this degree of cost savings is unlikely to be feasible. However, it would be reasonable to expect a degree of cost savings associated with the flexibility in supply purchase timing associated with incremental storage capacity. ICF calculated a rough assessment of the potential savings to be C$106,522 per year per PJ of storage capacity based on the ability to shift five days per month of high-priced purchases to the average monthly price excluding the five highest price days. The monthly average prices and the 5-day high prices at Dawn are shown in Table E 1.

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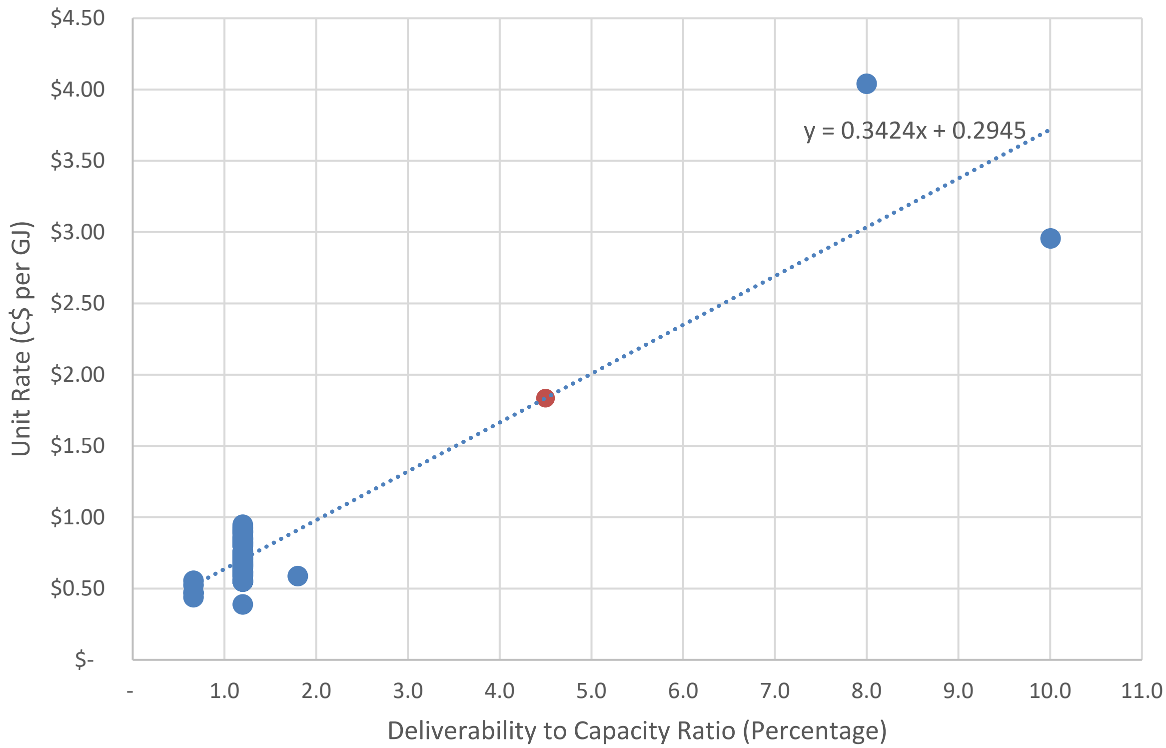
[34] Excluding the value associated with storage space.
[35] Based on 1.2 percent deliverability. (1.2 * 0.3424) + (0.2945*0) = $0.41 per GJ
[36] STAR storage report for October 2021.xlsx (enbridgegas.com)
[37] https://www.enbridgegas.com/-/media/Extranet-Pages/Storage-and-transportation/operational-information/Index-of-customers/Storage_Report.ashx?rev=298043dc1c2241c9abf2a8a4ac8aa2d2&hash=9DA9849B78F15C206654F1E299C018B7
[38] Two high deliverability storage contracts with deliverability exceeding 10% of the storage space were excluded from the regression analysis. These contracts were designed to provide a specific service to power generation customers and were considered outliers for this analysis. Inclusion of these outliers would have increased the cost of the market-based services and delivered services estimated in this report and have reduced the cost effectiveness of these alternatives to this analysis .

Exhibit E 1 : Scatter Plot of Enbridge Gas Storage Contracts' Unit Rate and Deliverability to Capacity Ratio



Incremental Storage Value

Overall ICF estimated that the value of firm peak period incremental deliverability associated with storage capacity would increase the value of storage by $410,880 per PJ of storage capacity, while the ability to avoid purchases during the highest priced market periods would increase the value of storage by at least $106,522 per year.[39] Together, these two value streams increase the value of incremental storage capacity by at least $517,402 per PJ of storage capacity per year.

[39] The value of the ability to avoid purchases during the highest price periods reflects a small portion of the extrinsic value of storage that could be achieved through the use of the storage capacity for daily price arbitrage. ICF has not calculated the extrinsic value of storage as part of this analysis.

Table E 1: Monthly Average prices and the 5-day high Prices at Dawn (US$/ MMBtu)

Average Monthly Price of Gas at Dawn Ex 5 Highest Price Days (US$/MMBtu)					
Year	**2018**	**2019**	**2020**	**2021**	**2022**
January	3.5	2.9	1.9	2.5	4.0
February	2.6	2.6	1.7	3.5	4.4
March	2.5	2.8	1.6	2.5	4.6
April	2.8	2.4	1.6	2.5	6.3
May	2.6	2.4	1.6	2.7	7.7
June	2.8	2.1	1.6	3.0	7.2
July	2.8	2.1	1.7	3.5	6.5
August	3.0	2.0	2.0	3.8	8.2
September	2.9	2.1	1.7	4.7	
October	3.3	1.8	1.9	5.1	
November	4.1	2.5	2.3	4.9	
December	3.7	2.2	2.4	3.7	
Average of Five Highest Price Days of Gas at Dawn (US$/MMBtu)					
Year	**2018**	**2019**	**2020**	**2021**	**2022**
January	6.3	3.8	2.1	2.7	4.8
February	3.0	3.0	1.8	6.4	5.2
March	2.6	4.3	1.7	2.7	5.2
April	3.8	2.6	1.8	2.7	7.1
May	2.8	2.5	1.9	2.8	8.5
June	2.9	2.3	1.7	3.4	8.7
July	2.8	2.3	1.8	3.8	8.4
August	3.1	2.1	2.2	4.1	8.9
September	3.0	2.4	2.1	5.2	
October	3.5	2.4	2.9	5.8	
November	4.9	2.8	2.8	5.4	
December	4.6	2.4	2.6	4.2	
Difference Between 5 Highest Price Days of Gas at Dawn and Monthly Average Ex 5 Highest Price days (US$/MMBtu)					
Year	**2018**	**2019**	**2020**	**2021**	**2022**
January	2.8	0.8	0.2	0.2	0.8
February	0.4	0.3	0.1	3.0	0.8
March	0.1	1.5	0.2	0.2	0.6
April	1.0	0.2	0.2	0.2	0.8
May	0.2	0.1	0.2	0.1	0.8
June	0.1	0.1	0.1	0.4	1.5
July	0.1	0.2	0.1	0.3	1.8
August	0.1	0.1	0.3	0.3	0.7
September	0.1	0.3	0.4	0.6	
October	0.2	0.6	1.0	0.7	
November	0.8	0.2	0.5	0.5	
December	0.9	0.2	0.2	0.4	
Annual Average	0.6	0.4	0.3	0.6	1.0

Gas Supplies to Operations

Line No.	Particulars (TJ)	Utility	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Supply									
1	Western Canadian Sedimentary Basin	EGI	84,994	93,110	109,683	117,955	119,669	116,275	114,640	118,685
2	Ontario / Dawn	EGI	132,716	216,565	209,798	129,680	129,756	147,664	132,639	126,720
3	Appalachia	EGI	0	17,333	97,432	96,987	94,649	100,116	100,125	100,399
4	Chicago	EGI	124,941	97,084	54,783	47,521	52,062	64,813	71,242	71,438
5	Niagara	EGI	80,333	79,846	79,524	80,042	79,994	80,720	80,651	80,923
6	U.S. Mid-Continent	EGI	14,025	13,469	14,886	18,232	21,938	21,951	21,950	22,011
7	Michigan	EGI	37,449	28,156	0	0	0	0	0	0
8	Gulf Coast	EGI	6,496	0	0	0	0	0	0	0
9	Unsecured	EGI	0	0	0	0	0	0	41	7,056
	Total System Supply		480,954	545,562	566,105	490,418	498,068	531,539	521,288	527,231
10	Direct Purchase Deliveries	EGI	231,456	237,671	250,834	243,040	240,639	242,711	244,120	245,246
11	Storage (Injection) / Withdrawal	EGI	(875)	(26,701)	(22,699)	790	(18,438)	(8,896)	(1,080)	427
12	Total	EGI	711,536	756,532	794,240	734,247	720,269	765,353	764,329	772,904

GAS COST REFERENCE PRICE

RACHEL GOODREAU, MANAGER REVENUE AND COST OF GAS

DAVE JANISSE, MANAGER GAS SUPPLY ACQUISITIONS

1. The purpose of this evidence is to request OEB approval of a common reference price methodology to set gas costs for Enbridge Gas, effective January 1, 2024. The reference price is used to price sales service commodity, gas in storage (a component of rate base), unaccounted for gas (UFG), company use, and compressor fuel, as part of the revenue requirement for the 2024 Test Year. As these costs have been consolidated for the amalgamated utility, a common reference price is required to support the 2024 Test Year Forecast as part of this Application.

2. Using the proposed reference price methodology, Enbridge Gas has calculated a common reference price of \$5.309/GJ (\$207.493/10^3m^3) for the 2024 Test Year. The reference price will be updated for the most recent OEB-approved QRAM as part of the draft rate order process, in accordance with the filing requirements.

3. In addition to the reference price proposal described in this evidence, Enbridge Gas is proposing to use the proposed reference price in the derivation of gas supply commodity rates for customers who choose to buy their natural gas supply from the utility under sales service. A description of the proposed gas supply commodity rate design is provided at Exhibit 8, Tab 2, Schedule 2. Setting a common reference price also allows Enbridge Gas to simplify and consolidate the gas supply deferral and variance accounts, which are provided at Exhibit 9, Tab 1, Schedule 2.

4. This evidence is organized as follows:
    1. Reference Price Harmonization
    2. Current Approved Reference Prices
    3. Proposed Reference Price
    4. Implementation

1. <u>Reference Price Harmonization</u>

5. A reference price is a unit rate representative of natural gas market pricing used to calculate the utility cost of gas for gas in storage, UFG, company use and compressor fuel. The unit rate may include varying components of gas supply related costs, depending on the reference price methodology. The components of gas supply costs that may be included in a reference price include gas supply commodity, transportation, storage and load balancing costs, which are provided at Exhibit 4, Tab 2, Schedule 1.

6. Enbridge Gas is proposing to introduce a common reference price for the amalgamated utility that will replace the current approved reference prices for the EGD and Union rate zones. The proposed common reference price would provide consistency and simplicity in approach, while continuing to ensure that the approach is formulaic and reflects appropriate market pricing. Consistent with current practice, the reference price will continue to be set quarterly as part of the Quarterly Rate Adjustment Mechanism (QRAM).

7. A common reference price recognizes the integrated nature of the amalgamated utility operations and gas supply processes, including combining the existing Gas Supply Plans for the EGD and Union rate zones into one consolidated plan, as provided at Exhibit 4, Tab 2, Schedule 1. The proposed reference price also ensures that Enbridge Gas customers pay the same gas cost unit rate for gas in

storage, UFG, company use, and compressor fuel regardless of where they are located in the franchise area. This approach aligns with and underpins other proposals in this Application to harmonize the gas cost recovery mechanisms, including cost allocation, rate design, and deferral and variance accounts, as provided at Exhibits 7, 8 and 9, respectively. As such, it is appropriate to bring forward the proposal for a common reference price as part of this Application.

8. This proposal is also consistent with the objectives outlined in the OEB report from the Natural Gas Forum[1], which were described in the QRAM Standardization proceeding as follows:

> The Board stated that the QRAM should be a transparent benchmark that reflects market prices and should reflect an appropriate trade-off between market prices and price stability. The Board further noted that the method for determining the reference price should be formulaic and consistent across natural gas utilities, as should the methods for determining and disposing of PGVA balances.[2]

2. Current Approved Reference Prices

9. Currently, Enbridge Gas uses various reference prices for the EGD and Union rate zones. Table 1 summarizes the OEB-approved reference prices from the April 2022 QRAM for the four existing rate zones. The reference prices are derived using a 21-day average of market settlement prices for a 12-month forward period.

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[1] Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005.
[2] EB-2008-0106, Amended Decision and Order, September 21, 2009.

Table 1
April 2022 QRAM Reference Prices

Line No.	Rate Zone	Reference Price	$/GJ (1)	$/$10^3m^3$ (1)
			(a)	(b)
1	EGD (2)	PGVA Reference Price	5.996	231.041
2	Union South	Dawn Reference Price	5.269	206.123
3	Union North East	Dawn Reference Price	5.269	206.123
4	Union North West	Alberta Border Reference Price	4.618	180.656

Notes:
(1) Conversion based on approved heat values of 38.53 GJ/10^3m^3 for EGD rate zone and 39.12 GJ/10^3m^3 for Union rate zones.
(2) The PGVA Reference price is based on the EGD rate zone portfolio and is used in PGVA calculations. The gas supply commodity charge for EGD rate zone is based on the Western Canada (Empress) price of $4.7071/GJ ($181.3667/10^3m^3).

2.1. EGD Rate Zone – Current Approved Reference Price

10. In the EGD rate zone, Enbridge Gas uses a PGVA reference price to price gas in storage, UFG, company use, and compressor fuel. The EGD methodology was last reviewed as part of a stakeholder consultation in 2017[3] and it was determined that a change to the methodology was not warranted at the time.

11. The PGVA reference price is based on the forecasted gas supply commodity costs[4], upstream transportation costs, and load balancing costs. The PGVA reference price unit rate is derived by dividing these forecast gas costs by the OEB-approved gas supply volumes. As the PGVA reference price is set based on a combination of forecast gas supply commodity, transportation and load balancing

[3] EB-2017-0086, Exhibit H1, Tab 2, Schedule 2, September 25, 2017.
[4] OEB-approved volumes at 12-month forward gas prices based on 21-day average of market settlement prices.

costs, Enbridge Gas uses the OEB-approved cost allocation and rate design to allocate and recover the gas costs accordingly.

12. Enbridge Gas uses a Western Canada price at Empress[5] inclusive of fuel as the base to set gas supply commodity rates for sales service customers in the EGD rate zone. Any price premium for gas supply purchased at other locations over the Empress price is recovered as transportation or load balancing costs. A description of the current approved rate design is provided at Exhibit 8, Tab 2, Schedule 2.

13. The PGVA reference price for the EGD rate zone is \$5.996/GJ (\$231.041/10^3m^3) based on the April 2022 QRAM. Please see Attachment 1 for the detailed calculations.

2.2. Union Rate Zones – Current Approved Reference Prices

14. In the Union rate zones, Enbridge Gas uses a Dawn reference price to price gas in storage, UFG, company use, and compressor fuel. The Dawn reference price is also used as the base to set gas supply commodity rates for sales service customers in the Union North East and Union South rate zones. The Alberta Border reference price is used as the base to set gas supply commodity rates for sales service customers in the Union North West zone, as the gas supply to serve this rate zone is primarily purchased in Western Canada at Empress.

15. The use of the Dawn reference price and Alberta Border reference price was approved by the OEB in 2015 to reflect Union's gas supply portfolio at the time, and

[5] Empress is located at the pipeline interconnect between the NOVA Gas Transmission System and TransCanada Mainline at the border of Alberta and Saskatchewan.

to reduce the variance between the actual cost of gas and the reference price set each quarter in QRAM.[6]

16. The Dawn reference price is \$5.269/GJ (\$206.123/10^3m^3) and the Alberta Border reference price is \$4.618/GJ (\$180.656/10^3m^3) based on the April 2022 QRAM. Please see Attachment 2 for the detailed calculations.

3. Proposed Reference Price

17. Enbridge Gas is proposing to harmonize to a common reference price used to set gas costs, effective January 1, 2024. The proposed reference price will be used to calculate the utility cost of gas for gas in storage (a component of rate base), UFG, company use, and compressor fuel, as these costs have been consolidated for the amalgamated utility. To ensure Enbridge Gas customers pay the same gas cost unit rate for these costs, a common reference price is required to derive the revenue requirement for the 2024 Test Year as part of this Application.

18. Enbridge Gas is also proposing to use the proposed reference price in the derivation of gas supply commodity charge for customers who choose to buy their natural gas supply from the utility under sales service. Please see Exhibit 8, Tab 2, Schedule 2 for the proposed gas supply commodity rate design.

19. In developing a proposed harmonized reference price methodology, Enbridge Gas considered the following three alternatives:
    1. Adopt a PGVA reference price consistent with the EGD rate zone;
    2. Adopt a Dawn reference price consistent with the Union South and Union North East rate zones; and

[6] EB-2015-0181, OEB Decision and Order, March 17, 2016.

3. Establish a modified approach based on a forecasted weighted average price for natural gas supply.

20. Enbridge Gas evaluated the alternatives based on how each option best met the objectives of a reference price as listed below:
    - reflect market prices on an ongoing basis;
    - be simple and transparent;
    - promote customer understanding and awareness; and
    - to the extent possible given market price fluctuations, produce gas supply commodity rates and customer impacts that are relatively stable and predictable over time.

21. Based on a review of the alternatives and consideration of the objectives of a harmonized reference price, Enbridge Gas is proposing Alternative 3, to set the reference price based on the forecasted weighted average price of the gas supply commodity and transportation costs related to gas supply purchases, for sales service customers, effective January 1, 2024.

3.1. Derivation of the Proposed Reference Price

22. The proposed weighted average reference price is set based on the forecast gas supply costs. The costs incorporate the gas supply commodity from the various sources of supply in the gas supply portfolio and the transportation contracts for gas supply sourced upstream of Dawn or Empress to provide diversity of supply for sales service customers.

23. The proposed reference price does not include the gas supply transportation[7] and load balancing[8] costs that are incurred on behalf of both sales service and direct purchase (DP) customers. By excluding these costs from the derivation of the reference price, the weighted average price reflects the costs incurred to provide a gas supply option to sales service customers only.

24. The proposed weighted average reference price is \$5.309/GJ (\$207.493/10^3m^3). Please see Attachment 3 for the detailed calculations of the proposed reference price based on the 2024 Gas Supply Plan using April 2022 QRAM prices. The gas supply prices reflect a 21-day average of market settlement prices for a 12-month forward period at each of the supply points in the 2024 Gas Supply Plan, as provided at Exhibit 4, Tab 2, Schedule 1. This approach to setting the gas supply prices is consistent with the current approved methodology for setting reference prices.[9] The reference price will be updated for the most recent OEB-approved QRAM as part of the draft rate order process, in accordance with the filing requirements.

25. The heat value used to derive the proposed reference price is based on the proposed harmonized Enbridge Gas South heat value of 39.08 GJ/10^3m^3, as provided at Exhibit 3, Tab 6, Schedule 1. Enbridge Gas will continue to follow the same approach used for the Union rate zones, which uses one annual heat value

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[7] The gas supply transportation costs include the upstream transportation capacity contracted on the TransCanada Mainline to move gas supply for sales service customers and bundled DP deliveries to the TransCanada delivery areas (Centrat MDA, Union WDA, Union SSMDA, Union NDA, Union NCDA, Union EDA, Enbridge CDA and Enbridge EDA).
[8] The load balancing costs primarily include upstream transportation capacity on the TransCanada Mainline to meet the demands of sales service and bundled DP customers that are above average day demands, either from storage or load balancing purchases. The load balancing costs also include planned purchases at Dawn for load balancing requirements and the cost of peaking services.
[9] EB-2008-0106, Amended Decision and Order, September 21, 2009, p.10.

for gas cost conversions when budgeting for gas costs and for ratemaking purposes.

3.2. Rationale and Benefits of the Proposal

26. Enbridge Gas is proposing a weighted average reference price instead of adopting the current approved Dawn or PGVA reference prices for the amalgamated utility. The proposed weighted average reference price reflects the diversity of supply and corresponding market prices of the gas supply portfolio, which results in a reference price that it is formulaic, transparent and easy to understand. The proposed reference price is also set based on the forecast gas supply costs for Enbridge Gas, which eliminates any forecast recovery variances between the forecast gas supply costs and the forecast recovery based on the gas supply commodity rates.

Proposed vs Dawn Reference Price

27. Enbridge Gas is proposing to move away from a supply point specific reference price, such as the Dawn reference price in favour of the weighted average reference price.

28. The Dawn reference price has historically been lower than the forecast upstream gas supply costs (including both commodity and transportation) that are required to serve sales service customers. As such, the forecast gas commodity rates based on the Dawn reference price do not fully recover all gas supply costs. Variances between the Dawn reference price and the forecast gas supply costs are captured in the PGVA and are recovered as gas commodity price adjustments (rate riders). These price adjustments (rate riders) are not included in the determination of bill impacts outside of the QRAM process, which results in less transparency of the total bill impact to customers in these rate zones.

29. Further, the forecast prospective cost variance captured in the PGVA balances for the Union South and Union North East rate zones can be significant. Based on the April 2022 QRAM, the forecast prospective cost recovery variance for the period of April 2022 to May 2023 is approximately $80 million as provided at Exhibit 6, Tab 1, Schedule 2, Section 2.1. By setting the gas supply commodity rate based on the weighted average reference price, the rate will recover the gas supply portfolio costs on a forecast basis, resulting in a prospective cost recovery variance of zero. This approach is consistent with the PGVA reference price for the EGD rate zone and the Alberta border reference price for the Union North West rate zone, which are also set to recover the forecast gas supply costs and results in a prospective cost recovery variance of zero.

Proposed vs PGVA Reference Price

30. Although the proposed weighted average reference price is similar to the current PGVA reference price used in the EGD rate zone, there is one notable difference. The proposed weighted average reference price includes costs incurred to provide a gas supply option to sales service customers only, compared to the PGVA reference price that also includes transportation and load balancing costs. By including the costs to provide sales service only, the weighted average reference price acts as a better price signal for sales service customers because it only includes costs that are attributable to the purchase of gas supply. It also allows the gas supply commodity rate to be set based on the weighted average reference price, without any additional cost allocation or rate design required. Please see Exhibit 8, Tab 2, Schedule 2 for the proposed gas supply commodity rate design.

3.3. Comparison of Reference Prices

31. The proposed reference price compared to the current approved reference prices for each rate zone is provided at Table 2 and described below.

Table 2
Reference Price - Proposed vs Current Approved
Based on April 2022 QRAM

Line No.	Particulars	Reference Price	$/GJ (1)	$/10^{3}m^3 (1)
			(a)	(b)
		Proposed		
1	EGI	Weighted Average Reference Price	5.309	207.493
		Current		
2	EGD (2)	PGVA Reference Price	5.912	231.041
3	Union South	Dawn Reference Price	5.269	206.134
4	Union North East	Dawn Reference Price	5.269	206.134
5	Union North West	Alberta Border Reference Price	4.618	180.659

Notes:
(1) Conversion based on proposed heat value of 39.08 GJ/10^{3}m^3 for the proposed reference price and approved reference prices of 38.53 GJ/10^{3}m^3 and 39.12 GJ/10^{3}m^3 for the EGD and Union rate zones, respectively.
(2) The PGVA Reference price is based on the EGD rate zone portfolio. The gas supply commodity charge for EGD rate zone is based on the Western Canada price at Empress of $4.7071/GJ ($181.3667/10^{3}m^3).

32. The weighted average reference price is less than the PGVA reference price used in the EGD rate zone, as the PGVA reference price includes transportation and load balancing costs to move gas to the Enbridge CDA and Enbridge EDA, compared to the weighted average price that only includes gas supply commodity and transportation contracts for gas supply sourced upstream of Dawn or Empress to provide diversity of supply.

33. The weighted average reference price is greater than the Dawn and Alberta Border reference prices in the Union rate zones, as they are based on one supply location,

compared to the proposed price, which incorporates all supply locations included in the gas supply portfolio as well as the cost of transportation to move natural gas to Enbridge Gas's franchise area for gas supply sourced upstream of Dawn or Empress. The price premium above the Dawn reference price is currently recorded in the PGVA for the Union South and Union North East rate zones and recovered through gas supply commodity price adjustments (rate riders).

4. Implementation

34. Enbridge Gas is proposing to implement the weighted average reference price effective January 1, 2024. The reference price is used to derive certain utility costs as part of the revenue requirement for the 2024 Test Year, such as gas in storage (a component of rate base), UFG, and compressor fuel. As these costs have been consolidated for the amalgamated utility, a common reference price is required to support the determination of the 2024 Test Year revenue requirement as part of this Application.

35. This proposal also supports other harmonization proposals for cost allocation, rate design and gas cost deferral and variance accounts, as provided at Exhibits 7, 8 and 9, respectively. The harmonization proposals for gas supply deferral and variance accounts are proposed to be implemented effective January 1, 2024, as provided at Exhibit 9, Tab 1, Schedule 1.

36. In order to implement January 1, 2024, it is necessary for Enbridge Gas to initiate work in 2023 to address the internal business application and process changes required to harmonize the reference price and gas supply deferral and variance accounts. The costs associated with the IT system changes have been included in the Asset Management Plan, as provided at Exhibit 2, Tab 6, Schedule 2, pages

248-251. In 2023, Enbridge Gas will also develop harmonized consolidated QRAM schedules to be filed in support of reference price changes as part of the January 1, 2024 QRAM Application.

Calculation of EGD Reference Price at April 2022 QRAM

Line No.	Particulars	Supply (TJ)	Supply (10^3m^3)	Gas Costs ($000s)	Average Costs ($/$10^3m^3$)	Average Costs ($/GJ)
		(a)	(b)	(c)	(d) = (c / b)	(e) = (c / a)
	Supply					
1	Western Canadian Sedimentary Basin	80,294	2,083,929	358,750	172.151	4.468
2	Ontario / Dawn	102,099	2,649,848	553,917	209.037	5.425
3	Appalachia	42,361	1,099,416	185,931	169.118	4.389
4	Chicago	25,031	649,655	136,684	210.394	5.461
5	Niagara	73,000	1,894,628	394,671	208.311	5.406
6	Unsecured	266	6,902	3,539	512.712	13.307
7	Total Supply	323,050	8,384,378	1,633,492	194.826	5.056
	Transportation					
8	TCPL Long Haul			113,769		
9	TCPL Short Haul			109,591		
10	TCPL Niagara			13,876		
11	Nexus			44,579		
12	Vector			13,609		
13	Nova			8,222		
13	Total Transportation			303,647		
14	Total Commodity and Transportation Costs	323,050	8,384,378	1,937,139	231.041	5.996

Notes:

(1) EGD rate zone heat value is 38.53 GJ/ 10^3m^3.

Calculation of Alberta Border and Dawn Reference Prices
For the 12 month period ending March 31, 2023

Line No.	Particulars	Apr-22 (a)	May-22 (b)	Jun-22 (c)	Jul-22 (d)	Aug-22 (e)	Sep-22 (f)	Oct-22 (g)	Nov-22 (h)	Dec-22 (i)	Jan-23 (j)	Feb-23 (k)	Mar-23 (l)	Total or Average (m)
	Days	30	31	30	31	31	30	31	30	31	31	28	31	365
1	NYMEX 21 Day Average (US$/MMBtu) (1)	4.405	4.422	4.466	4.517	4.525	4.508	4.530	4.619	4.780	4.881	4.722	4.298	4.556
2	Foreign Exchange	1.272	1.272	1.272	1.272	1.272	1.272	1.273	1.273	1.273	1.273	1.273	1.273	1.273
	Calculation of Alberta Border Reference Price													
3	Empress Basis (US$/MMBtu)	(0.661)	(0.780)	(0.837)	(0.862)	(1.028)	(0.941)	(0.863)	(0.727)	(0.726)	(0.763)	(0.661)	(0.666)	(0.793)
4	Alberta Border (Cdn$/GJ) (2)	4.513	4.391	4.375	4.406	4.218	4.301	4.423	4.695	4.892	4.970	4.902	4.384	4.539
5	Forecast Purchase Volume - Union North West (PJ)	1.55	1.12	0.72	0.51	0.54	0.80	1.41	1.94	2.00	2.00	1.81	2.00	16.42
6	Cost at Market Price ($000s) (line 4 * line 5)	6,983	4,910	3,159	2,263	2,297	3,429	6,249	9,108	9,805	9,962	8,874	8,787	75,826
7	Alberta Border Reference Price (Cdn$/GJ) (line 6 / line 5)	4.513	4.391	4.375	4.406	4.218	4.301	4.423	4.695	4.892	4.970	4.902	4.384	4.618
	Calculation of Dawn Reference Price													
8	Dawn Basis (US$/MMBtu)	(0.082)	(0.162)	(0.237)	(0.299)	(0.304)	(0.323)	(0.344)	(0.230)	(0.179)	(0.122)	(0.031)	0.038	(0.190)
9	Dawn (Cdn$/GJ) (3)	5.211	5.136	5.098	5.085	5.091	5.047	5.050	5.294	5.551	5.742	5.662	5.234	5.267
10	Forecast Purchase Volume -South	12.52	12.94	12.52	12.94	12.94	12.52	12.94	12.13	12.54	12.54	11.33	12.54	150.38
11	Forecast Purchase Volume - NE	1.94	2.01	1.94	2.01	2.01	1.94	2.01	3.05	3.16	3.16	2.85	3.16	29.23
12	Forecast Purchase Volume - Union South and Union North East (PJ)	14.46	14.94	14.46	14.94	14.94	14.46	14.94	15.19	15.69	15.69	14.18	15.69	179.61
13	Cost at Market Price ($000s) (line 9 * line 10)	75,362	76,763	73,729	75,995	76,077	72,995	75,465	80,406	87,122	90,126	80,257	82,144	946,442
14	Dawn Reference Price (Cdn$/GJ) (line 11 / line 10)	5.211	5.136	5.098	5.085	5.091	5.047	5.050	5.294	5.551	5.742	5.662	5.234	5.269

Notes:
(1) 21 Day Strip dates used: January 31 to February 28, 2022.
(2) Alberta Border Price = ((NYMEX 21 Day Average (line 1) + Empress Basis (line 3)) * (Foreign Exchange Rate (line 2)) / MMBtu to GJ conversion rate (4).
(3) Dawn Price = ((NYMEX 21-Day Average (line 1) + Dawn Basis (line 8)) * (Foreign Exchange Rate (line 2)) / MMBtu to GJ conversion rate (4).
(4) MMBtu to GJ conversion rate: 1.055056 GJ /MMBtu.

Calculation of EGI Reference Price at April 2022 QRAM

Line No.	Particulars	Supply (TJ)	Supply (10^3m^3)	Gas Costs ($000s)	Average Costs ($/$10^3m^3$)	Average Costs ($/GJ)
		(a)	(b)	(c)	(d) = (c / b)	(e) = (c / a)
	Supply					
1	Western Canadian Sedimentary Basin	118,685	3,036,983	520,433	171.365	4.385
2	Ontario / Dawn	126,720	3,242,569	667,501	205.856	5.268
3	Appalachia	100,399	2,569,061	487,894	189.911	4.860
4	Chicago	71,438	1,827,986	391,116	213.960	5.475
5	Niagara	80,923	2,070,700	398,241	192.322	4.921
6	U.S. Mid-Continent	22,011	563,217	117,460	208.552	5.337
7	Unsecured	7,056	180,546	38,583	213.700	5.468
8	Total Supply Costs	527,231	13,491,062	2,621,228	194.294	4.972
	Transportation Costs - System Gas					
9	TCPL Niagara			15,218		
10	Nexus			105,008		
11	Vector			23,678		
12	U.S. Mid-Continent			19,421		
13	Nova			8,222		
14	Great Lakes			6,528		
15	Total Transportation Costs - System Gas			178,075		
16	Total Supply and Transportation Costs - System Gas	527,231	13,491,062	2,799,304	207.493	5.309

DESIGN CRITERIA AND DESIGN DEMANDS PROCESS

HILARY THOMPSON, DIRECTOR, S&T BUSINESS DEVELOPMENT

TRACEY TEED MARTIN, DIRECTOR ENGINEERING

1. The purpose of this evidence is to provide, and request OEB approval for, Enbridge Gas's proposed harmonized design criteria and process for determining its design demands. Enbridge Gas provides safe and reliable delivery of natural gas to serve customer natural gas requirements at a reasonable cost. Enbridge Gas accomplishes this by sizing its transmission, storage and distribution system assets and developing its Gas Supply Plan to meet the design demands of its customers. Design demands are determined using design criteria.

2. For a natural gas utility, design criteria are the weather conditions, usually temperature and wind speed, used to determine design demands. The Enbridge Gas service area is situated in a colder climate. Consequently, demand for natural gas fluctuates throughout the year with demand for natural gas being highest in the winter and lowest in the summer. Design criteria and the resultant design day demands allow Enbridge Gas to size its assets and evaluate facility and non-facility alternatives for periods of high demand, in particular the highest demand conditions which occur on very cold days.

3. Enbridge Gas, as the provider of last resort, endeavours to size its pipeline systems to minimize the risk of failure in its ability to deliver gas to its customers. Customers are inherently risk adverse and expect to be able to heat their homes and operate their businesses on the coldest days. A less conservative design criteria condition will lower the reliability of the pipeline systems and will have a higher risk of failure with costs of that failure including the utility cost to make safe and relight

customers, municipal cost to manage the emergency, and societal cost for property damage and economic losses. Enbridge Gas's proposed approach to determine design demand and its selection of design criteria aligns with the no failure approach in that it captures the coldest weather event experienced. It is a proven method used by Union and a majority of other utilities. It is an approach that is clear, simple, and repeatable.

4. The design demands need to reflect customers observed behaviour not only on design day but throughout the year. Estimating design demands that reflect actual behaviour is critical to provide the reliability Enbridge Gas's customers expect. The design criteria is a primary input into the design demand process. The goal of Enbridge Gas's design demand process is to align the actual customer experienced demand and weather impact throughout the various geographies in the franchise area and create a predictive model that reliably forecasts customer year-round asset needs into the future. This process is also critical to the evaluation and expansion of new technologies such as renewable natural gas or hydrogen injection. Assessment of customer demand and asset needs throughout the year is vital to be able to assess, plan for, and take advantage of these opportunities.

5. Enbridge Gas's upstream gas supply, storage, transmission, and distribution systems are integrated and interdependent. Due to the integrated nature of these facilities, the underlying processes to estimate the design demand used to design the gas supply, storage, transmission, and distribution assets also need to be harmonized. The design criteria and design demand processes need to consider not only the design conditions but also the impact on day-to-day system operations when evaluating potential changes in approach. The processes must be able to estimate demand for the planning cycle which extends over the entire year as well as at the design condition.

6. A probabilistic method was used by EGD with a one in five-year recurrence level. A one in five-year recurrence level assumes that system failures may take place once every five years. The EGD method was specifically designed for gas supply planning functions, which was to support contracting for space on upstream transportation systems. EGD did not have transmission systems to transport its gas commodity to the utility and as such the risk was placed on the supply points where spot gas could be acquired to mitigate shortfalls on the one in five-year recurrence level. To prevent distribution system failures, a condition that is unacceptable to its customers, EGD also included engineering assumptions that further reduced the risk of not meeting the design day demand. As an amalgamated utility, this approach is not appropriate for integrated transmission, distribution, and storage assets. Design demands need to be granular and aligned to actual observed customer behaviour and very cold weather.

7. Enbridge Gas is proposing to adopt the method used by Union to determine its design criteria, with modifications. Enbridge Gas is proposing that the design criteria be determined using the coldest day on record, as measured by heating degree days (HDDs) for a specified timeframe, adjusted for wind speed. This method is referred to as the set temperature method. The resultant design criteria will be expressed as heating degree days adjusted for wind speed or HDDw[1]. As provided at Exhibit 3, Tab 2, Schedule 5, Attachment 1, Enbridge Gas is proposing to change the base temperature used to calculate HDD to 15°C. The analysis set out in this Exhibit uses HDD values that have been calculated using this proposed base temperature.

[1] HDDw is also known as effective degree days in the energy industry.

8. Enbridge Gas is proposing to adopt the Union method for determining its design demands. There are two design demand conditions used by Enbridge Gas for determining the size of its assets and to evaluate facility and non-facility alternatives[2]: design day demand and design hour demand. Design day demand, or the highest expected firm demand for natural gas on a day, is used for transmission and storage system planning as well as gas supply planning. Design hour demand, used for distribution system planning, is the highest expected firm demand in an hour for natural gas within a day. Design hour demand is assumed to occur on the design day. Both design demands will be determined using regression analysis, with minor exceptions, with the design criteria as an input.

9. The proposed methods for determining design criteria and design demands have been accepted by the OEB in prior applications. The set temperature method has been used in the Union North rate zone for over 40 years and has been used in the Union South rate zone since 2013. Regression analysis has been used to determine design demands by EGD and Union for many years. Furthermore, the Synergi software package used by EGD and Union for the hydraulic modelling of the pipeline system is currently in use by 323 organizations globally, including the majority of distribution companies in North America. Attachment 1 contains a report completed by Guidehouse Canada Ltd. (Guidehouse) for Enbridge Gas which examines the approaches to determining design criteria and design demands for other utilities across North America. The Guidehouse Report finds that the proposed method for determining design criteria is used by a majority of comparator gas distribution utilities throughout North America.

[2] Those assets comprising the Gas Supply Plan and its transmission, storage and distribution systems.

10. The proposed methodology, in conjunction with the energy transition assumptions as provided at Exhibit 1, Tab 10, Schedule 4, results in an overall reduction in identified distribution system reinforcements while transmission and storage assets remain consistent with previous forecasts as shown in the Asset Management Plan provided at Exhibit 2, Tab 6, Schedule 2. The other harmonized design activities include coincident peak diversification of large volume customers on shared distribution systems, declining average use, using energy transition forecast trending on distribution systems, and general alignment of modelling approaches and parameters. The impact to customers is minimal as a result of these harmonization activities and the proposed design criteria and design demand methods. Gas Supply Plan demands are higher in the EGD CDA which are partially offset by reduced demands in Union South, Union NDA, Union EDA, and EGD EDA.

11. This evidence is organized as follows:
    1. Importance of Design Criteria and Design Demand to a Utility and its Customers
    2. Third-Party Interpretation of Design Criteria & Design Demand Methodologies
    3. Design Criteria
    4. Design Demands
    5. Results and Impacts of the Harmonized Proposal for Design Day Demand
    6. Summary

1. Importance of Design Criteria and Design Demand to a Utility and its Customers

12. Enbridge Gas provides a critical service to its customers consisting of the procurement, transportation and storage (as required)[3], and distribution of natural gas. This service allows customers to operate their natural gas fired equipment used for building heat, water heating, cooking, laundry, electricity generation, and manufacturing processes.

13. Critical infrastructure such as buildings, bridges, storm water detention systems, electrical system infrastructure, and gas system infrastructure have design criteria. It is recognized that failure of this type of infrastructure can have serious economic and loss of life impacts and thus their design criteria is used to set safety and reliability standards and are used to complete their design. For example, highway bridges and storm water detention facilities in Ontario are designed for a 1 in 100-year flood event. It is recognized that having bridges or storm water detention facilities fail during flood events is consequential. Similarly, Enbridge Gas also has design criteria, specifically the design HDD, to size its assets to be reliable during very cold weather conditions to prevent failure to deliver scenarios and the resulting consequences as previously discussed.

14. Enbridge Gas, as the service supplier of last resort, is accountable for the safe and reliable delivery of natural gas to meet customer service expectations throughout the year and most importantly during very cold weather events. This means ensuring there is enough gas supply, physical pipeline, compression, and storage

[3] Enbridge Gas provides procurement and upstream transportation for a subset of Enbridge Gas customers which do not typically include unbundled or semi-unbundled customers. Unbundled and semi-unbundled customers have their own upstream gas supply arrangements to deliver natural gas to the utility.

assets to transport natural gas from supply locations (within and upstream of Enbridge Gas's franchise area) to the customer meter.

15. Customers expect natural gas service will be available when they need it. They expect to have heat throughout the winter and during very cold weather events, to have hot water on demand, and to be able to prepare food on demand. Businesses expect to have natural gas to operate, provide services, or manufacture goods. The IESO expects electricity from natural gas power generators when required for grid and price stability[4].

16. Based on feedback from the Enbridge Gas 2024 Customer Rate Rebasing Engagement Report, provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 54, by Innovative Research Group, Inc., customers have an expectation that they will not lose gas service during times of very cold weather and are concerned about being negatively affected due to loss of natural gas service.

> Both residential and business participants are concerned about losing their natural gas supply in winter. Especially in the North, participants view loss of heating in the winter as a health and safety threat with the potential for loss of life. There are also concerns about physical

[4] The electricity system in Ontario is constantly evolving, as exemplified within the government of Ontario's most recent announcement on October 7, that in order to ensure system reliability and keep costs down Ontario is proceeding with its plan to procure up to 1,500 MW of natural gas-fired electricity generation to resolve a projected shortfall beginning in 2025 and 2026. Ontario. (2022, October 7). Ontario Building More Electricity Generation and Storage to Meet Growing Demand. News Release. https://news.ontario.ca/en/release/1002373/ontario-building-more-electricity-generation-and-storage-to-meet-growing-demand
IESO has also recently concluded that phasing out natural gas electricity generation by 2030 is not feasible and would result in blackouts, and replacing natural gas fired electricity generation by 2030 would increase residential electricity bills by at least 60%. IESO. (2021, October 7). Six things to know about the IESO's study on phasing out gas-fired generation by 2030. Powering Tomorrow. https://www.ieso.ca/en/Powering-Tomorrow/2021/Six-things-to-know-about-the-IESOs-study-on-phasing-out-gas-fired-generation-by-2030

> damage as pipes could freeze and burst…Some business participants are also concerned about business interruption. Not only does loss of natural gas impact heating for businesses, for some it is a critical component of their production process whether that be supplying ovens, industrial dryers or forges. Losing natural gas means shutting the business down.

17. Having widespread customer outages during very cold weather conditions has significant economic consequences and, in the extreme, can result in loss of life. Recent events in Texas illustrate the damage that can occur when a utility is unprepared for cold weather events.

> The UT-Austin report found that Uri, although not the most severe Texas winter storm on record, caused the most loss of electricity… multiple factors caused those extended blackouts, including that ERCOT underestimated peak demand by nearly 14 percent and weather forecasts misjudged the severity and timing of the storm… 210 people perished because of Winter Storm Uri...many residents found conditions within their homes unbearable, with indoor temperatures at or below freezing…. Although Winter Storm Uri's devastation continues to be tallied, early estimates of the storm's economic toll, as mentioned, range from $80 billion to $130 billion — the result of power loss, physical infrastructure damage and forgone economic opportunities.[5]

18. Further information on the consequences of a large-scale customer outage of Enbridge Gas's system was provided in Union's Parkway West Project evidence.

[5] Texas Comptroller of Public Accounts. (2021 October). Winter Storm Uri 2021 The Economic Impact of the Storm, https://comptroller.texas.gov/economy/fiscal-notes/2021/oct/winter-storm-impact.php

For residential customers that solely heat their homes using natural gas, a disruption of service would mean their home has no heat. Depending upon the length of the outage the water supply would need to be shut off to each residence to avoid water damage due to bursting pipes, where possible. Enbridge estimates that on a 35-degree day (-17 degrees Celsius) a typical home would drop below 0 degrees Celsius in approximately 14 hours (EB-2012-0451: Application, Exhibit A, Tab 3, Schedule 3, page 9). Outages greater than a day or two would have a significant impact on the health and wellness of GTA residents if they remained in their homes. Municipalities may need to invoke warming centres fueled by another energy source and relocate some or all of the impacted residents as part of emergency response plans. Residents, as well as restoration crews, would need to relocate outside of the impacted area or to facilities within the impacted area not heated by natural gas.

If service cannot be restored quickly, low system pressure and customer outages will occur which would affect the safety and health of residents within parts of the Enbridge franchise. Citizens most at risk would be those that lack mobility such as senior citizens who could experience life threatening circumstances.

Restoration of natural gas service is a much more complex process than when electrical service is interrupted. Restoring gas service is time and resource intensive, expensive, inconvenient to homeowners and a burden on emergency crews on a much more massive scale than electric service restoration. Large outages could not be managed expediently using only company crews and would require support from other utilities through the Canadian Gas Mutual Aid Assistance Agreement as well as heating and cooling professionals. Restoring service means crews must go neighbourhood-by-neighbourhood and house-to-house closing meter valves and then reopening at each meter, relighting pilot lights, as necessary, as service is restored. This requires at least two visits to each customer; one to safely shut in the service and the other to safely restore the service and light up furnaces and appliances. Logistically restoration of service becomes much more difficult if a portion of the population is relocated or housed in warming centres. Recently Enbridge estimated that restoration of natural gas service by gas technicians to 25,000 to 50,000 customers could take between 6,600 and 13,200 person hours, or 275 to 550 person days (EB-2012-0451: Exhibit A, Tab 3, Schedule 23, page 8).

In its 2010 Reliability Working Group, Enbridge estimated the cost of restoring service in the event of a natural gas outage to be about $12 million per 100,000 customers and that an outage of hundreds of thousands of customers could take months to restore service. The cost of damages to property, restricted industrial production and foregone business sales would be in addition. (EB-2010-0231: Exhibit D, Tab 1, Schedule 2, Appendix E, page 11).[6]

19. Enbridge Gas's assets are of critical importance to the safety of its customers and the economy of Ontario. In its August 2006 Incident Analysis titled "Ontario-U.S. Power Outage – Impacts on Critical Infrastructure"[7] , Public Safety and Emergency Preparedness Canada recognized the potential impact of a natural gas outage.

A high percentage of the Canadian population and industry are dependent upon natural gas as a main energy source. During the winter months, a disruption to the natural gas supply would seriously impact residents who are reliant on natural gas as their sole heat source. Alternative accommodation would need to be located for the affected population. Most schools, businesses, offices, public

[6] EB-2012-0433, Section 8, pp.73-77, paragraphs 37-40.
[7] This report analyzed the impact of the August 2003 electricity system blackout which left approximately 50 million people in Canada and the U.S. without power.

> buildings and industries are also dependent on natural gas and would likely have to be closed if there was a disruption to service. In addition, the petro-chemical industry uses natural gas for feedstock. Moreover, a number of electrical generators and co-generators are fuelled by natural gas, which may not be able to convert to other forms of energy.[8]

20. Enbridge Gas plans for a no failure of service approach to provide service reliability to customers during the coldest weather events that Enbridge Gas has actually experienced. The storage, transmission, and distribution systems as well as the upstream Gas Supply Plan assets need to be planned and sized to serve the estimated highest firm customer demand during the coldest weather events experienced by the utility. This is due to the recognition that the utility's pipeline infrastructure cannot be constructed on short notice. If customer demand is greater than Enbridge Gas's asset capacity, Enbridge Gas may lose the ability to serve customers during peak periods and on the design day.[9] It is also difficult, costly and time consuming to restore service to customers.

21. The less conservative the design criteria assumed when sizing a pipeline system, the greater the likelihood is that a design demand condition will exceed the systems capability to serve it. A less conservative design condition will lower reliability of a system and will have a higher risk of failure with costs of that failure including the utility cost to make safe and relight customers, municipal cost to manage the emergency, and societal cost for property damage and economic losses. Conversely, the more conservative the design criteria assumed when sizing a

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[8] Ontario-U.S. Power Outage-Impacts on Critical Infrastructure, August 2006, p.21, http://cip.management.dal.ca/publications/Ontario%20-%20US%20Power%20Outage%20-%20Impacts%20on%20Critical%20Infrastructure.pdf
[9] Due to the reliance upon natural gas fired power generation in the province, there is the potential to also lose portions of the electricity grid as well.

pipeline system, the likelihood a design demand condition will exceed the systems capability to serve it is lessened, however there is cost associated with the additional assets and gas supply.

22. In addition to incorporating design criteria assumptions when determining design demands, other assumptions and parameters are used to mitigate risk of system failure. One example is the inclusion of wind speed when calculating design criteria. Another example is the diversification factors assumed when modelling transmission and distribution system asset requirements.

23. There is a balance that needs to be maintained between safety, reliability and reasonable cost. As previously discussed, customer engagement results indicated that customers have an expectation that they will not lose gas service during times of very cold weather and are concerned about being negatively affected due to loss of natural gas service.

24. The design criteria and design demands are developed to allow Enbridge Gas to provide safe and reliable service at a reasonable cost to meet customer needs and maintain system reliability while planning for very cold weather events that have actually been experienced. Design demand planning ensures the utility has the assets and services required to meet the needs of customers to avoid a failure to deliver scenario entirely.

25. Enbridge Gas's upstream gas supply, storage, transmission, and distribution systems are integrated and interdependent. Due to the integrated nature of these facilities, the underlying processes to estimate the design demand used to design the gas supply, storage, transmission, and distribution assets also need to be harmonized. The design criteria and design demand processes need to consider

not only the design conditions but also the impact on day-to-day system operations when evaluating potential changes in approach. The results from the processes used to estimate design day and design hour demand are an input into the Gas Supply Plan, determine pipeline system capacity, plan corresponding facility, non-facility (including integrated resource planning alternatives (IRPAs) and hybrid solutions that feed into the Asset Management Plan (AMP)), and are also used to manage, operate, and maintain the pipeline systems on a day-to-day basis. The processes must be able to estimate demand for the entire planning cycle which extends over the entire year as well as at the design condition.

26. Harmonized methodologies for determining design criteria and design demands are required for gas supply planning and pipeline system design for the storage, transmission and distribution systems for the amalgamated utility.

2. Third-Party Interpretation of Design Criteria & Design Demand Methodologies

27. The EGD and Union rate zones use different methods to determine the design criteria and design demands. The Union rate zones use a coldest day on record which is also known as the set temperature method (with wind speed adjustment) to determine the design criteria. The EGD rate zone uses a probabilistic method with a one in five-year recurrence interval (without wind speed adjustment) to determine the design criteria. The EGD and Union rate zones both use regression analysis to determine design demands.

28. In its 2012 ESM proceeding[10], Union responded to an OEB-directive to provide an expert and independent review of its Gas Supply Plan, its gas supply planning process, and gas supply planning methodology. As part of meeting that directive

[10] EB-2013-0109.

Union filed a report authored by Sussex Energy Advisors (Sussex Report) which addressed Union's Gas Supply Plan and the processes and methodologies (including the design criteria and design demands) used to develop the Gas Supply Plan. The Sussex Report found that the set temperature approach was appropriate and similar to the design criteria used by other gas distribution utilities. The Sussex Report recommended minor changes to Union's design criteria. The OEB indicated that it was appropriate for Union to adopt the recommendations made in the Sussex Report.

29. The Guidehouse Report, provided at Attachment 1, confirms that the set temperature approach continues to be used by many gas distribution utilities throughout North America. Table 2-1 of the Guidehouse Report sets out the methods used by comparator utilities to determine their design criteria. The set temperature approach is the most common amongst the comparator utilities in the Guidehouse Report.

30. In addition to Guidehouse's jurisdictional review of design day criteria, Enbridge Gas requested Guidehouse review the elements of Enbridge Gas's proposed approach to its design day methodology and identify the degree to which these elements are consistent with the comparator utilities evaluated in the Guidehouse Report as provided at Attachment 1, Section A.2. This includes components of design day criteria including temperature selection, sample period, HDD wind adjustment methodology and design day demand modelling approach. Guidehouse concluded that Enbridge Gas's proposed design day criteria is consistent with the approach used by comparable utilities evaluated in the Guidehouse Report.

31. When determining the design criteria and design demand proposals provided in this Exhibit, Enbridge Gas considered input from prior OEB decisions, research on industry best practices, and the approaches used by EGD and Union. Enbridge Gas also considered its planning principles and planning cycle. The design criteria were evaluated through each of its key components in relation to how it supports the objectives of system design as well as reflecting actual design conditions and system operation. The set temperature method is consistent with a no failure approach to system design as it assumes the coldest weather observed. The proposed approach for design day demand was previously accepted by the OEB. The approach for design hour demand was already similar for both EGD and Union. Enbridge Gas determined that adoption of the Union approach to design criteria and design demands, with minor adjustments, was most appropriate. Enbridge Gas reflected this decision in its AMP and Gas Supply Plan. Development of the AMP and other planning processes are resource intensive such that it is not practical to develop multiple scenarios under different planning assumptions.

3. Design Criteria

32. This section sets out Enbridge Gas's proposed harmonized method to determine the design criteria to select the design day heating degree day. Enbridge Gas requests that the OEB approve using the coldest observed heating degree day on record based on the details below.

33. HDD is a measurement designed to quantify the demand for energy needed to heat a building. Factors other than outside temperature can affect the energy needed to heat a building. Wind speed increases the amount of energy needed to heat a building as the wind wicks away heat from the building envelope and is similar to the impact of wind chill experienced by people. Temperature and heating degree

days (HDD) are related by the equation:

$$HDD = max(T_b - T, 0)$$

Where:

HDD = heating degree days

T_b = base temperature (degrees Celsius)

T = temperature or wind speed compensated temperature (degrees Celsius)

34. HDD is defined relative to a base temperature. This base temperature is the outside temperature below which a building needs heating to maintain a comfortable interior building temperature. The traditional base temperature used to calculate heating degree days is 18°C in North America. However, in practicality, the base temperature is dependent upon many factors including the level of insulation, air leakage and heat generating equipment in a building. As discussed earlier in this Exhibit, Enbridge Gas is proposing to use a balance point of 15°C to calculate HDDs.

35. Wind speed adjustments are an important factor in determining design criteria as wind impacts the amount of energy required by buildings for heating. Buildings lose more heat on a windy day than on a calm day. The wind speed adjustment recognizes that the impact of wind increases with HDD.

36. The design day heating degree day is the highest HDD expected to occur. It is the most important variable to determine design demand, size its assets, and the facility and non-facility alternatives required to provide safe and reliable service expected by its customers. This is because Enbridge Gas operates in a colder weather climate where most of its customers are heat sensitive and have their highest demand during very cold weather events.

37. An appropriate design day HDD is determined from an examination of historical temperature extremes. In the case of a gas distribution utility, this examination entails an analysis of very cold temperature conditions such as the coldest day for a specified time frame. This examination could also be conducted using a specified return interval or probability of occurrence over a specified time frame.

3.1. Proposal for Design Criteria

38. The choice in design day HDD determines risk, specifically how often customer demand will exceed the systems capability to serve it and the risk of customers losing their gas service. Enbridge Gas is proposing to use the set temperature method to determine its design criteria. Table 1 provides the proposed and existing design criteria for the Enbridge Gas service area in both base 15°C and 18°C for clarity. The proposed design criteria HDDw for each of the weather stations are determined by selecting the highest observed HDDw starting from November 1, 1979[11]. As can be seen in Table 1 most of the changes are driven by the proposed change in base temperature.

[11] Some weather stations do not have hourly temperature and wind speed data back to 1979.

Table 1
Proposed Design Day HDDw

		Proposed		Existing[12]			
Line No.	Weather Station	EGI HDD_w (1)	Occurrence date	Union HDD_w (2)	Union HDD_w (1)	EGD HDD (2)	EGD HDD (1)
		(a)	(b)	(c)	(d)	(e)	(f)
1	St Catharines	37.8	1/18/1994			38.8	35.8
2	London	40.8	1/18/1994	43.1	40.1		
3	Windsor (3)	41.3	1/30/2019				
4	Toronto	41.4	1/15/1994	45.7	42.7	41.4	38.4
5	Wiarton (3)	41.5	1/11/1981				
6	Sault Ste Marie	44.2	1/9/1982	48.2	45.2		
7	Kingston	44.3	1/3/1981	47.1	44.1		
8	Peterborough	45.1	1/15/1994			46.0	43.0
9	Barrie	46.1	12/19/2004			44.0	41.0
10	Ottawa	47.5	1/15/1994			48.2	45.2
11	Muskoka	48.5	1/15/1994	49.0	46.0		
12	Montreal (4)			49.2	46.2		
13	North Bay	48.7	1/3/1981	52.5	49.5		
14	Sudbury	50.6	1/9/1982	51.9	48.9		
15	International Falls	51	1/30/2019	54.7	51.7		
16	Earlton	51.5	1/17/1982	54.8	51.8		
17	Thunder Bay	51.6	1/9/1982	51.6	48.6		
18	Dryden (3)	53.2	1/9/1982				
19	Timmins	52.0	1/16/1982	55.7	52.7		
20	Kapuskasing	52.9	1/16/1982	55.6	52.6		
21	Geraldton (3)	53.4	1/27/2019				
22	Kenora (4)			55.9	52.9		

Notes:
(1) Based on 15°C base temperature.
(2) Based on 18°C base temperature.
(3) New weather station.
(4) Retired weather station.

39. The HDDw provided in Table 1 are calculated using Environment Canada hourly temperature and wind speed data. The hourly temperature data is adjusted for the

impact of the hourly wind speed using a widely accepted method developed by Marquette Analytics[13]. Using this method, the temperature is adjusted to account for wind speed based on the following equations:

$$HDDw = \frac{(WS + 152)}{160} * HDD, WS < 8$$

$$HDDw = \frac{(WS + 72)}{80} * HDD, WS \geq 8$$

Where:

HDDw = heating degree days adjusted for wind speed

WS = wind speed

HDD = heating degree days

40. Once the hourly wind speed adjusted temperatures are calculated they are converted into HDDw using a base temperature of 15°C. The hourly HDDws are averaged to align with the hourly average and these results are then averaged over a 24-hour period aligned to the gas day, from 10:00 am eastern standard time on the current day to 9:59 am eastern standard time on the next day. The highest HDDw from the November 1, 1979, becomes the design criteria for each weather station.

41. Enbridge Gas proposes to continually track HDDw for each of the weather stations. If the design criteria provided in Table 1 are exceeded, Enbridge Gas will update its

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[12] For clarity, the existing design criteria for Union and EGD use 18˚C as the base temperature as shown in columns (c) and (d), respectively. The columns under “Existing” that include 15˚C as the base temperature are provided for information to draw line of sight relative to the proposed HDD_w in column (a) for comparison.

[13] Marquette Energy Analytics, for more than 25 years, is the United States premier energy demand forecasting service, providing demand forecasts for natural gas, electric distribution utilities and delivered fuels. It is responsible for forecasting gas demand for more than 20% of America with their flagship product, Gas Day.

design criteria to that new value.

42. The benefits of the coldest observed method are:
    a) It is an industry standard method used by several comparator natural gas utilities;
    b) It provides an appropriate and reasonable level of service reliability;
    c) It aligns with the no failure approach in that it captures the coldest weather event experienced;
    d) It is a proven method in the Union North and Union South rate zones;
    e) It has an approach that is clear, simple and repeatable; and
    f) It is a method previously accepted by the OEB.

4. Design Demands

43. This section sets out Enbridge Gas's proposed harmonized process to determine design demands. Enbridge Gas requests that the OEB approve the proposed harmonized process for determining design demands.

4.1. How Design Demand is Used

44. Design demand is used to identify system capacity and needs from which solutions are developed to reliably serve customers during very cold weather events and other high demand periods. Providing reliable service to meet customer expectations requires Enbridge Gas to forecast an appropriate level of design demand. This reduces the risk that Enbridge Gas will not be able to serve its customers during very cold weather events it has historically experienced or could potentially experience. The design criteria are the main factor that determines design demands. The design criteria used to determine design demands are the coldest weather events that are expected to occur based on historical records.

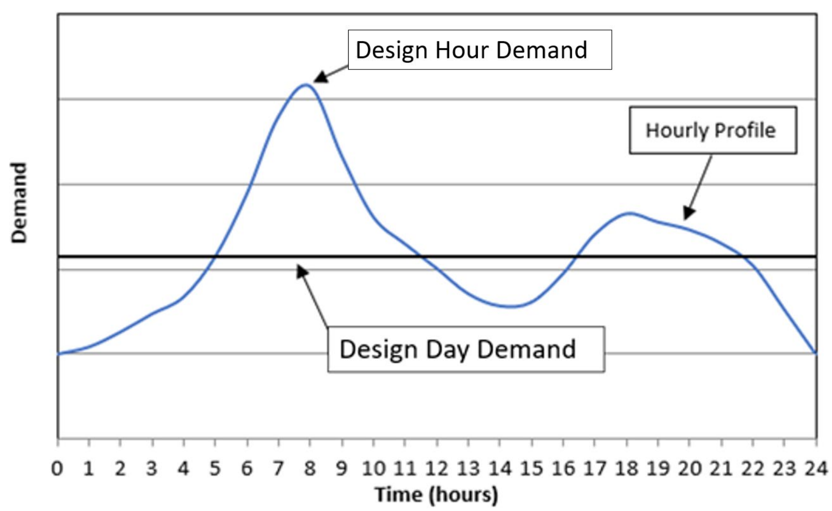
4.2. The Relationship Between Design Day Demand and Design Hour Demand

45. Enbridge Gas requires a harmonized approach to determine the design demands. A harmonized approach will result in efficient internal processes and appropriate asset requirements for its customers.

46. Design day demand, or the highest expected firm demand for natural gas on a day, is used for gas supply planning, and transmission and storage system planning. Design hour demand, used for distribution system planning, is the highest expected hourly firm demand for natural gas within a day. Design hour demand is assumed to occur on the design day.

47. The relationship between design day and design hour demand is illustrated in Figure 1.

Figure 1: Relationship Between Design Day and Design Hour Demand



48. Most customers, especially those who are heat sensitive, do not consume natural gas at a constant rate throughout the day. The black line in Figure 1 represents the design day demand while the blue line (labelled hourly profile) represents the hourly demand change over the design day. The design hour demand on design day is the hour corresponding to the highest point of the blue line. As Figure 1 shows, customers typically consume gas in a diurnal pattern, low at night when people are sleeping and higher during the day when people are active. As the morning hours approach, gas use increases to heat buildings and gas burning appliances such as hot water heaters. This usage peaks around 8 am along with a secondary smaller increase in the late afternoon and early evening. This pattern is referred to as an hourly profile.

49. An annual planning process allows Enbridge Gas to respond to customer demand changes including impacts from an increased number of customer attachments, general service customer changes, demand side management programs, contract rate customer contract changes, firm to interruptible switching, energy transition trends, integrated resource planning alternatives and local municipal energy plans. On an annual basis, system capacity, assets and services required to support design day and design hour demand are evaluated and modified, including analysis to determine the appropriate timing (including deferral) for facility and non-facility projects to reflect changes in the design demand. This information is updated annually in the AMP, Gas Supply Plan, and other Company processes. The development of the design day demand and design hour demand is part of the annual planning process.

4.3. Proposal for Design Demand Process

50. This section sets out Enbridge Gas's proposed harmonized process to determine the design demands which includes both design day demand and design hour demand.

Design Day Demand Process

51. The design day demand is the estimated highest firm volumetric amount of natural gas that is estimated to be consumed by customers on the coldest day. The proposed process for determining design day demand is as follows:
    a) Linear regression analyses completed by delivery area[14];
    b) Actual daily measured volumetric demand[15];
    c) Prior winter data;
    d) Weather data in the form of HDDw from geographically associated weather stations;
    e) Weekends and holidays are removed from the analysis;
    f) Resulting regression line is extrapolated to the design day HDDw;
    g) Existing general service demand data details include:
        i. Calculated for groups of customers using city gate station flow minus contract rate customers[16]
        ii. Includes demand diversity or non-coincident usage[17]

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[14] The delivery areas include Enbridge CDA, Enbridge EDA, Union MDA, Union WDA, Union NDA, Union NCDA, Union SSMDA and Union EDA and along Dawn Parkway, Panhandle, Sarnia Industrial Line known as Union South.
[15] Measured at city gate stations and contract rate customer stations.
[16] Measured at city gate stations and contract rate customer stations.
[17] Non-coincident means that customers' equipment and processes cycle and that they do not consume their maximum demand at exactly the same time. This non-coincident usage is termed demand diversity and results in a lower demand compared to each customer's peak demand being added together.

iii. Adjusted by the use per customer factor[18]

h) Existing contract rate demand data details include:
   i. Calculated for groups of contract rate customers[19]
   ii. Includes demand diversity or non-coincident usage[20]
   iii. Demand reservations for some process customers[21]
   iv. Interruptible demand is curtailed

i) Company's demand forecasts for new and existing customers are added to the existing customers design day demand to become the estimated forecast design day demand[22].

52. Using the previous winter's (most recent) data is the most appropriate starting point for determining design day demand. This process closely follows the Union approach to determine design day demand. It ensures the most recent customer behaviour is incorporated into the design day demand. The previous winter's data reflects the myriad of factors which impact demand including demand side management, economic factors, customer behaviour, and energy efficiency. Going forward the use of the previous winter's data will also incorporate IRPAs and energy transition.

[18] The existing customer general service design day demand is adjusted using the ratio of general service demand divided by the number of general service customers. The use per customer has a gradual downward trend over time which reflects observed energy efficiency gains or process or behavioural changes.
[19] Measured at contract rate customer stations.
[20] Non-coincident means that customers' equipment and processes cycle and that they do not consume their maximum demand at exactly the same time. This non-coincident usage is termed demand diversity and results in a lower demand compared to each customer's peak demand being added together.
[21] Some non-heat sensitive contract rate customers require a demand reservation and are not subject to this process. Customer design day demand in this case is based on equipment ratings and historical usage which is reflected in the customer contracted demand which is contained in the customer's distribution contract with Enbridge Gas.
[22] For energy transition assumptions used for input variables to design day demand, see Exhibit 1, Tab 10, Schedule 4.

53. The Union method for developing design day demands has performed well over the more than 40 years this method has been used.

54. Figures 2 and 3 show a graph of the results for the South rate zone for Winter 2018/2019 and Winter 2021/2022[23]. The analysis is shown by demand vs. heating degree day. The circles represent the actual measured customer demand[24]. The line shown is the forecast demands as calculated using the current Union method. This line was the estimate of that winters demands as calculated using the previous winters data plus the demand changes based on the forecast inputs.

[23] The results reflect the current Union methods, as the proposed method has some minor modifications the forecast line will be slightly but not materially different.

[24] The graphs do not include the power generation customers as their demand is very sporadic and require a demand reservation and four other very large industrial process customers which require demand reservations.

Figure 2: Winter 2018/2019 Design Day Demand Forecast vs. Actual Consumption – Demand vs Heating Degree Day

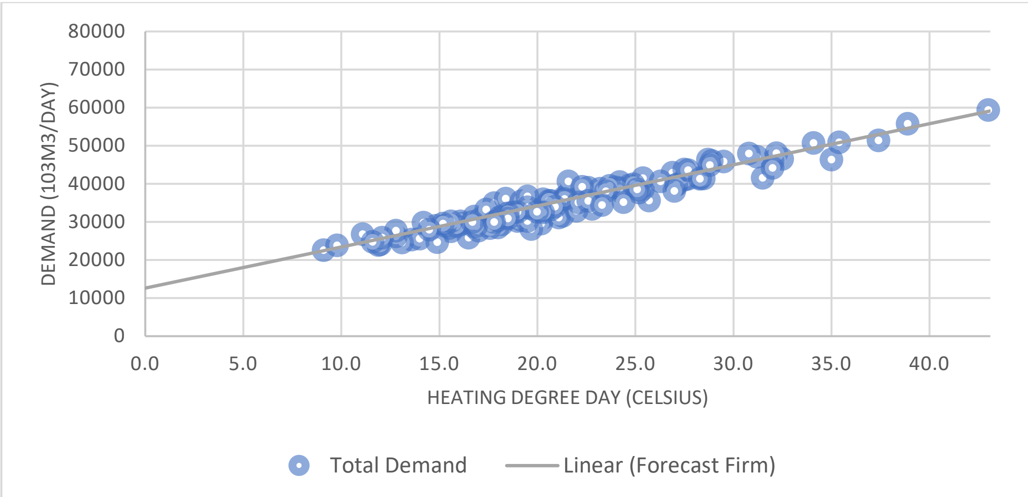
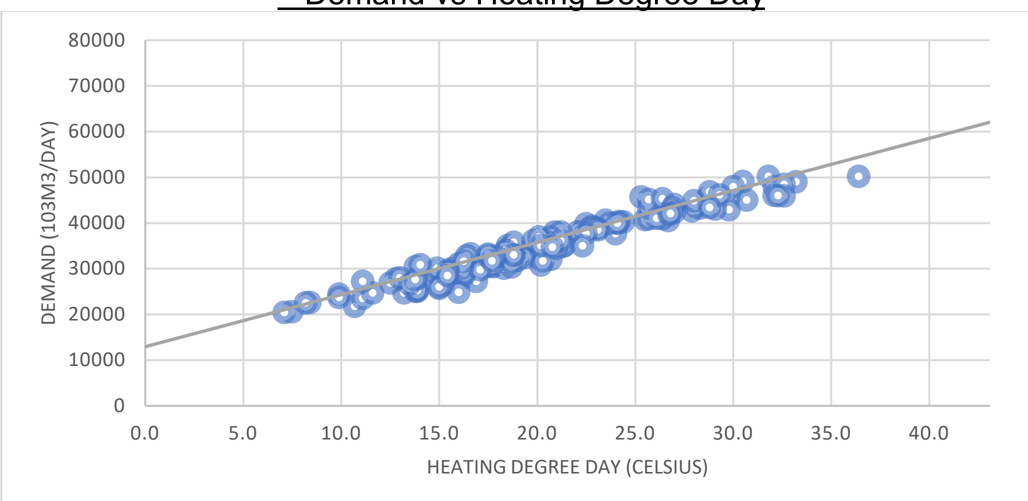


Figure 3: Winter 2021/2022 Design Day Demand Forecast vs. Actual Consumption – Demand vs Heating Degree Day



55. Figures 4 and 5 show a graph of the results for the South rate zone for Winter 2018/2019 and Winter 2021/2022[23]. The analysis is shown by demand vs. date. The blue line represents the actual measured customer demand[24]. The orange line shows the forecast demands as calculated using the current Union method. This

line was the estimate of that winters demands as calculated using the previous winters data plus the demand changes based on the forecast inputs.

Figure 4: Winter 2018/2019 Design Day Demand Forecast vs. Actual Consumption – Demand by Date

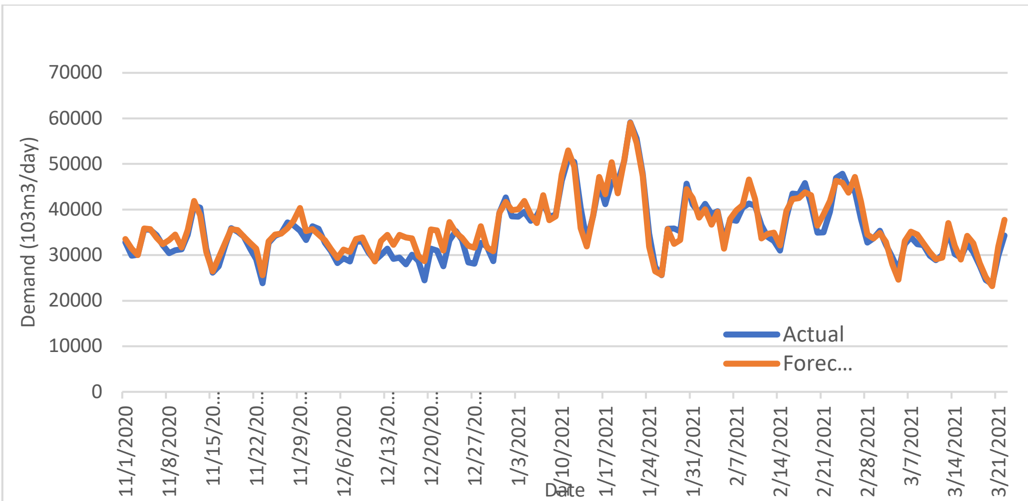
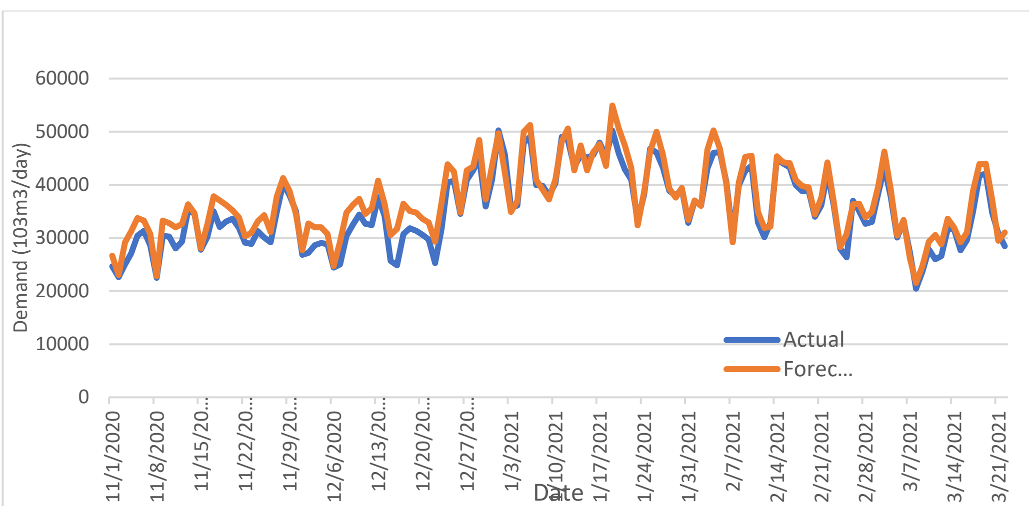


Figure 5: Winter 2021/2022 Design Day Demand Forecast vs. Actual Consumption – Demand by Date



56. Of note, the results from Winter 2018/2019 are shown in Figure 2 and 4, January 30, 2019, was a 43.0 HDDw (the third highest recorded) compared to the existing design day HDDw of 43.1 for London weather station. The actual consumption on that day was 59,125 10^3m^3/day compared to the forecast design day demand of 59,020 10^3m^3/day. The design day demand on that day was 102% of the forecast demand.

57. The average difference and range between the actual measured demands and the forecast is shown in Table 2.

Table 2
Average Difference and Range between Actual and Forecast Demands

Line No.	Winter (%)	Average Difference between Actual and Forecast	Range of Difference between Actual and Forecast
		(a)	(b)
1	2018/2019	0.98	0.83 to 1.12
2	2021/2022	0.95	0.78 to 1.08

Design Hour Demand Process

58. The design hour demand is the estimated highest firm volumetric amount of natural gas that is estimated to be consumed by customers in an hour on the coldest day. The proposed process for determining design hour demand is as follows.

59. The general service design hour demand is estimated using:
    a) Linear regression analysis completed for each customer;
    b) Monthly customer billing data;
    c) Prior two years data;

d) Monthly weather data in the form of HDDw from geographically associated weather stations;
e) Monthly data is converted into daily demand;
f) Resulting regression line is extrapolated to the design day HDDw;
g) The results are adjusted to align with data available from city gate stations;
    i. Linear regression analyses completed by distribution network.
    ii. Actual daily measured volumetric demand
        1. Calculated for groups of customers using city gate stations minus contract rate customers[25].
        2. Includes demand diversity or non-coincident usage[26]
    iii. Prior winter data;
    iv. Weather data in the form of HDDw from geographically associated weather stations;
    v. Weekends and holidays are removed from the analysis;
    vi. Resulting regression line is extrapolated to the design day HDDw;
h) Daily demand is converted into design hour demand[27];
i) Company demand change forecasts for new and existing customers are added to the existing customer design day demand to become the estimated forecast design hour demand[28].

60. The contract rate design hour demand is estimated using:

[25] Measured at city gate stations and contract rate customer stations.
[26] Non-coincident means that customers' equipment and processes cycle and that they do not consume their maximum demand at exactly the same time. This non-coincident usage is termed demand diversity and results in a lower demand compared to each customer's peak demand being added together.
[27] Using empirically derived profiles based on actual hourly flow data from the same gate stations.
[28] For energy transition assumptions used for design hour demand, see Exhibit 1, Tab 10, Schedule 4.

a) Actual hourly measured volumetric demand[29];
b) Prior five years data;
c) Demand reservations for some process customers[30];
d) Interruptible demand is curtailed;
e) Company demand change forecasts for new and existing customers are added to the existing customer design day demand to become the estimated forecast design hour demand.

61. The existing EGD and Union methods for design hour are almost identical to each other and, as such, there is very little to harmonize. The Union method has two additional steps incorporated into the harmonized method above as items (g) and (h), of paragraph 59, that refine the results and are included in the proposed harmonized method. The proposed design hour demand method is harmonized with the design day demand method as the design hour demand is adjusted to align with the design day demand in step (g). This step results in the distribution, transmission, storage and Gas Supply Plan being aligned and harmonized.

62. Once the design day and design hour demand has been determined it is assigned to the appropriate location in the storage, transmission, and distribution system hydraulic models based on the geo-assigned coordinates of the individual customers of distribution system flow rates. Hydraulic modelling (network analysis) is completed to determine the system capacity and its ability to serve the design day or design hour demand.

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[29] Measured at contract rate customer stations.
[30] Some non-heat sensitive contract rate customers require a demand reservation and are not subject to this process. Customer design day demand in this case is based on equipment ratings and historical usage which is reflected in the customer contracted demand which is contained in the customer’s distribution contract with Enbridge Gas.

63. The proposed process for determining design day and design hour has performed well for Union in determining design day and design hour demand and developing corresponding storage, transmission, distribution and Gas Supply Plan.

5. Results and Impacts of the Harmonized Proposal for Design Day Demand

64. The design day demand developed from the harmonized process outlined above for Winter 2023/2024 are provided in Table 3. This table shows the design day demand in TJ/day for Enbridge Gas's delivery areas as shown in columns (a) through (j). The existing methodology is shown in lines 1-3 while the proposed method is shown in lines 4-6. The difference between the two methodologies is shown in lines 7-8. All interruptible demand has been curtailed.

Table 3
Winter 2023/2024 Design Day Demand

Line No.	Particulars (TJ/d)	EGD CDA	EGD EDA	Union MDA	Union WDA	Union NDA	Union NCDA	Union SSMDA	Union EDA	Union South	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Existing										
1	Firm Bundled / Semi-unbundled	3,372	715	6	88	167	42	42	179	3,327	7,939
2	Firm Unbundled	584	0	0	31	103	3	61	207	0	987
3	Firm Total	3,956	715	6	118	270	45	103	386	3,327	8,926
	Proposed										
4	Firm Bundled / Semi-unbundled	3,485	698	6	88	155	45	42	173	3,283	7,973
5	Firm Unbundled	584	0	0	31	103	3	61	207	0	987
6	Firm Total	4,069	698	6	119	257	47	102	379	3,283	8,960
7	Difference (line 6 – line 3)	113	(17)	0	1	(13)	3	(1)	(7)	(44)	34
8	% of Firm Total (line 7 / line 3)	2.9%	(2.4%)	(0.5%)	0.7%	(4.7%)	5.7%	(0.8%)	(1.8%)	(1.3%)	0.4%

Note:
(1) Includes firm demands. Interruptible demand has been curtailed.

65. The proposed harmonized method increases the design day demand by 0.4% or 34 TJ/d and includes an increase of 113 TJ/d in the EGD CDA offset by decreases in the EGD EDA, Union North and Union South rate zones of 17 TJ/d, 17 TJ/d, and 44 TJ/d, respectively. These changes are the result of the proposed harmonized design criteria and design demand methods as described in this Exhibit, as well as harmonization and other changes of the Company's demand forecasts, energy transition assumptions, and interruptible customer curtailment policies.

Asset Management Plan Impacts

66. The distribution assets are the largest portion of assets contained in the AMP. As a result of the proposal of using the existing design hour process with the inclusion of the two Union refinements and the harmonized Company's demand forecasts, energy transition assumptions and interruptible curtailment processes, there are significantly less distribution facilities required to serve the design hour demand in the EGD rate zone.

> The combined impact to the AMP is a reduction of approximately $66 million excluding overheads, to the Distribution Reinforcement Capital forecast relative to the previously filed AMP. The comparison is limited to overlapping years between plans: 2023, 2024, and 2025.[31]

67. As a result of the proposal to use the Union design day demand method, there are no incremental transmission or storage facilities required to serve the design day demand as the process was refined but did not materially change. The facilities detailed in the AMP did not change because of this proposal.

[31] Exhibit 1, Tab 10, Schedule 4, Section 2.2.

Gas Supply Plan Impacts

68. The Union South, Union NDA and EGD EDA experience a decrease in design day demand, whereas EGD CDA experiences an increase in design day demand. Details on how Enbridge Gas plans to manage these changes within the Gas Supply Plan are provided at Exhibit 4, Tab 2, Schedule 1, Section 1.4.

6. Summary

69. Enbridge Gas's proposals for design criteria and design demand harmonize approaches across the entire service territory. The proposed methods are consistent with a no failure approach for providing natural gas supply because they result in asset and services requirements that are customized to the coldest weather experienced in each of the geographic areas across Enbridge Gas's franchise area. The methods are easy to implement, simple, repeatable, and have been in use in the Union rate zones for many years and are OEB accepted. In addition, the proposals do not result in any significant changes to asset requirements. Where demand requirements have changed in the Gas Supply Plan, Enbridge Gas will continue to follow the OEB's guiding principles for any required changes to the Gas Supply Plan.

Guidehouse

Approaches to Gas Design Day

Jurisdictional Review

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Reference No.: 218158
May 27, 2021
Appendix A2 added October 24, 2022

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Disclaimers

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1. Introduction

Enbridge Gas Inc. engaged Guidehouse to conduct a comparative analysis of industry practices used to determine weather and risk assumptions for Gas Supply Planning. As well, Guidehouse reviewed utility common practices for design day demand modeling, used for Gas Supply Planning in upstream contract sizing.

It is generally accepted and recognized in the energy industry that a gas utility is obligated to ensure that its natural gas system is able to provide uninterrupted gas service to its firm customers during the extreme weather conditions (i.e., design day temperatures) that underpin its gas delivery system design. Natural gas utilities must plan for sufficient delivery capacity and natural gas supply during periods of cold weather. As temperatures decrease, natural gas demand typically increases and can approach the capacity of the system.

In order to meet this obligation and provide a firm level of service to customers, gas utilities need to define a planning standard to establish the delivery system capacity, as well as its gas supply requirements. To accomplish this, gas utilities use a “Design Day” and a “Design Year” to inform the planning standards from which the development of a reliable supply portfolio and reliable deliver capacity can be established over a forecast period.

- Design Day: A design day for a gas distribution utility is a 24-hour period of the greatest theoretical gas demand.

- Design Year is the coldest planning year.

Design Day and Design Year are directly related to temperature and are typically measured in Heating Degree Days[1]. However, in some cases, it is measured in degrees, e.g., 0 degrees Fahrenheit, or -18 degrees Celsius.

In this report, Guidehouse examines the approaches used by North American natural gas utilities to construct their design day and how the design day planning standard informs the development of the natural gas utilities’ resource portfolios.

[1] Degree days are measures of how cold or warm a location is. A *degree day* compares the mean (the average of the high and low) outdoor temperatures recorded for a location to a standard temperature. In Canada, a HDD is equal to the number of degrees Celsius that a given day’s mean temperature is below 18º and usually 65° Fahrenheit (F) in the United States. The more extreme the outside temperature, the higher the number of degree days. A high number of degree days generally results in higher levels of energy use for space heating or cooling. Source: https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php#:~:text=Heating%20degree%20days%20(HDD)%20are,for%20the%20two-day%20period.

2. Summary of Key Findings

There is no one "set standard" or accepted best practice in the natural gas industry regarding the calculation of a Design Day. This observation is corroborated in reports that describe the design day approaches used by two of the natural gas utilities examined by Guidehouse in this report, including National Grid and Avangrid[2]. These reports (as filed with each utility's respective regulatory commission) state that there is no consensus or set standard in the industry regarding approaches to design day. Broadly, Guidehouse observes that there are two primary approaches used by gas utilities:

1. The Probabilistic Method: This approach involves calculating the probability of occurrence that the design day will occur in practice based on observed conditions over a historical period. This approach yields a 1 in X years result, or recurrence interval, of when an expected event, heating degree day or temperature, is expected to be equaled or exceeded in any given year[3].

2. A Coldest Observed Temperature: This approach involves identifying the actual coldest observed temperature over a period of time using one or more weather stations that are representative of the gas utility service area. This approach is sometimes called the Set Temperature Approach.

Guidehouse examined a group of comparator utilities. Across the identified set of peers, both methods are found to currently be in use. In addition to there being no "set standard," we observe that there is also no consistent methodological framework within each approach.

For example, gas utilities using the probabilistic approach often deploy different recurrence intervals. In addition, within one company that operates several different gas utility subsidiaries, Guidehouse identified the use of both the probabilistic and set temperature approaches. National Grid uses the probabilistic approach in Massachusetts and Rhode Island, albeit with different recurrence intervals, and uses the set temperature approach in its downstate NY (New York City and Long Island, NY) service territories.

Guidehouse observes that natural gas utilities disclose varying amounts of information and components of their process. For example, National Fuel Gas provides a detailed explanation of its overall approach including the use of hydraulic modeling to inform its gas supply planning, while others do not provide similar details. Guidehouse provides its observations based on publicly available data and cautions that the conclusions reached are based on information available in the public domain.

Table 2-1 summarizes the Design Day approach used by the comparator utilities. Guidehouse has found sufficient information on Design Day methodology and summarizes these details in this report.

[2] Avangrid: NYSEG/RG&E 2020-2021 Winter Supply Plan http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B36C8F36C-6F37-498A-8BAD-99F70168D3BE%7D and National Grid: https://www.nationalgridus.com/media/pdfs/other/ltng-supplementalreport.pdf

[3] A 1 in 10 years recurrence interval would mean that the assumed HDD level, or temperature, assumed on design day is expected to be experienced once every 10 years, on average. Or, there is a 10% probability that the specified design day value would be achieved in any given year.

Table 2-1. Summary of Key Findings

Utility	Jurisdiction	Design Day Approach	Probabilistic Interval	Set Temperature
National Grid – Boston Gas and Narragansett Electric	Massachusetts and Rhode Island	Probabilistic	1/40 Years	n/a
National Grid	Downstate New York (i.e., Brooklyn, Queens, Staten Island and Long Island)	Set Temperature	n/a	-18°C / 0°F
Public Service Electric and Gas (PSEG)	New Jersey	Set Temperature	n/a	-18°C / 0°F
New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E)	New York	Probabilistic	1/40 Years	n/a
Consolidated Edison (Con Edison)	New York	Set Temperature	n/a	-18°C / 0°F
DTE Energy	Michigan	Set Temperature	n/a	-21°C / -6°F
CenterPoint Energy Minnesota Gas	Minnesota	Probabilistic	Not specified	n/a
National Fuel Gas Distribution	New York	Set Temperature	n/a	-22.8°C / -9°F
Wisconsin Power & Light	Wisconsin	Set Temperature	n/a	-29°C / -21°F
Northern States Power Company	Wisconsin and Michigan	Set Temperature	n/a	-32°C / -27°F
EPCOR Natural Gas Limited Partnership (EPCOR)	Ontario	Unknown	Not specified	Not Specified

2.1 Factors Influencing Design Day Standards

Gas utilities must ensure that their natural gas systems are able to provide uninterrupted service to firm customers during extreme weather conditions. To facilitate peak service, utilities plan the system and sufficient supply using design day temperature criteria.

The inability to meet customer requirements during a period of peak usage can have negative consequences on customers and on the natural gas distribution system. In addition to potential damage from freeze-offs to residential and commercial buildings and the loss of economic production at commercial and industrial establishments, a significant loss of pressure can result in an uncontrolled shutdown and have impactful repercussions on the integrity of the gas utility distribution system.

In considering the utilities reviewed in this analysis, Guidehouse observes that National Grid is the only gas utility to do a cost-benefit analysis to determine the effective degree day level to which it should plan for firm deliverability. By evaluating the cost of holding capacity for when a Design Day occurs, versus the benefit of not incurring damages associated with shutting off service to customers who could incur freeze-up, National Grid estimates damages and economic loss to businesses.

Other factors influence Design Day analysis. These factors include the means by which the natural gas utility can serve peak Design Day requirements. Natural gas utilities typically build a gas supply plan by constructing a portfolio consisting of long-term firm contracts for pipeline transportation and storage, liquefied natural gas (LNG) and compressed natural gas (CNG) peak shaving facilities and, in some cases, mobile LNG or CNG trucks, in addition to supply contracts to meet customers' requirements.

2.2 Design Day Informs Natural Gas System Planning, Reliability and Resiliency

Guidehouse observes that the North American natural gas delivery system is inherently highly resilient and responsive to periods of peak demand, but that this resiliency and responsiveness is largely a feature of the ability to contractually access natural gas delivery infrastructure and supply. For example, a gas utility that is highly dependent on a single natural gas pipeline for access to supply is inherently less resilient than a gas utility with access to multiple upstream pipelines and supply sources.[4]

From a natural gas supply planning perspective, the Design Day informs the design of the natural gas delivery system (the distribution system) as well as the natural gas supply portfolio. Guidehouse observes that, although there is no single approach to establishing a Design Day, it is a critical input for determining the adequacy of existing supply resources, or the timing for new resource acquisitions or capital investments required to meet customers' natural gas needs during a peak use event.

2.3 Methodology

This document provides a high-level overview of the Gas Design Day processes of 10 utilities that have been identified as comparators. Guidehouse arrived at 10 comparators by applying a four-tiered filtering analysis to 60 natural gas utilities across North America. Guidehouse created this list by including the top 50 US natural gas distributors in the U.S. by sales[5] and

[4] https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf

[5] 2019 Ranking of Companies by Total Sales Customers. AGA Statistics Database. https://www.aga.org/contentassets/d68b868b7cd94ed2889b704b441ab469/1002totcust.pdf

supplementing the list with nine additional natural gas distributors in Canada[6] and two utilities owned by Avangrid[7] due their similarities to EGI. The four-tiered analysis evaluated and compared various utility characteristics to EGI. The tiers were applied to the list of utilities in phases. First, Tier 1 was applied, and if a utility passed Tier 1 then the Tier 2 and Tier 3 filtering criteria were applied. If utilities passed both Tier 2 and Tier 3, then the Tier 4 filtering criteria was applied. Tier 1 filtering was a binary pass or fail criteria, whereas Tier 2 and Tier 3 criteria were given weightings based on how important the criteria was when comparing utilities to EGI. The first three tiers of filtering are summarized in Table 2-2 below[8].

Table 2-2. Tier 1 to Tier 3 Comparator Filtering Analysis

Tier	Weight	Criterion	Strong = 3	Moderate = 2	Weak = 1	*Illustrative Example for Strong = 3*
Tier 1	N/A	Climate Zones	One of utility territory climate zone(s) are zone 6 or greater.*	N/A	All of utility territory climate zone(s) are zone 5 or less.	*Utility territory spans climate zones 5, 6 and 7.*
Tier 2	1	Type of Customers	Utility percent of residential customers is within 15% of Enbridge Gas'.	Utility percent of residential customers is within 15% to 50% of Enbridge Gas'.	Utility percent of residential customers is outside of 50% of Enbridge Gas'.	*Utility percent of residential customers is within 15% of Enbridge Gas'.*
Tier 2	1	Type of Heating Used by Customers	Utility percent of population that uses forced air furnace heating is within 15% of Enbridge Gas'.	Utility percent of population that uses forced air furnace heating is within 15% to 50% of Enbridge Gas'.	Utility percent of population that uses forced air furnace heating is outside of 50% of Enbridge Gas'.	*Utility percent of population that uses forced air furnace heating is within 15% of Enbridge Gas'.*
Tier 3	0.5	Number of Customers	Utility number of customers is within 25% of Enbridge Gas'.	Utility number of customers is within 25% to 75% of Enbridge Gas'.	Utility number of customers is outside of 75% of Enbridge Gas'.	*Utility number of customers is within 25% of Enbridge Gas'.*
Tier 3	0.5	Revenue	Utility revenue is within 15% of Enbridge Gas'.	Utility revenue is within 15% to 50% of Enbridge Gas'.	Utility revenue is outside of 50% of Enbridge Gas'.	*Utility revenue is within 15% ($680 million) of Enbridge Gas'.*
Tier 3	0.5	Volume	Utility total volume is within 15% of Enbridge Gas'.	Utility total volume is within 15% to 50% of Enbridge Gas'.	Utility total volume is outside of 50% of Enbridge Gas'.	*Utility total volume is within 15% (42 Bcf) of Enbridge Gas'.*

******The exception to this is utilities that service the cities of Boston and Chicago. Though they are both in climate zone 5, Guidehouse believes the cities to be comparable to Toronto.*

Guidehouse began the filtering process by applying the Tier 1 filtering criteria to the list of 60 utilities. To properly evaluate each utility based on the Tier 1 criteria, Guidehouse determined the climate zones that each utilities service territory spanned.[9] EGI spans climate zone 5 to 8, with most of its service territory covering climate zone 6 or higher. Therefore, Guidehouse concluded that any utility whose service territory spanned climate zone 6 or higher would pass Tier 1. The exception to this rule were utilities that serviced the cities of Boston and Chicago[10],

[6] The Canadian natural gas distributors included: ATCO, Altagas, EPCOR, Fortis BC Energy Inc., Manitroba Hydro, Heritage Gas, Energir, Emera Energy and SaskEnergy.

[7] NYSEG and RG&E

[8] Tier 4 was a qualitative analysis versus Tier 1 to Tier 3 are either binary or quantitative analysis; therefore, it was not included in Table 2-2, but is explained in detail later in this section.

[9] Based on ASHRAE climate zones.

[10] These utilities were Ameren Illinois, Peoples Gas Light and Coke Company, and Boston Gas Company d/b/a National Grid.

because both cities are in climate zone 5, and have extremely similar weather patterns to the city of Toronto. 35 of the 60 utilities evaluated passed the Tier 1 analysis. Please see Table A-1 for the list of utilities that passed the Tier 1 analysis.

The 35 utilities that passed Tier 1 were then subject to both the Tier 2 and Tier 3 analysis simultaneously. As stated previously, Tier 2 and Tier 3 criterion were each given a weight[11], and the success criteria (i.e., strong, moderate or weak) were each given a score[12]. This allowed Guidehouse to calculate an overall rating of each utility relative to EGI. The ratings were determined by summing the score of each criterion multiplied by the weighting of each tier. The overall rating assessed how comparable the utilities are to EGI. If a utility scored strong for each of the criteria across both tiers, the maximum rating they could receive was 11. The results of the Tier 2 and Tier 3 filtering analysis had utilities ratings ranging from 4 to 9. The ranking was determined by summing the score of each criterion multiplied by the weighting of each tier.

For the Tier 2 criteria “Type of Customers”, Guidehouse leveraged data from the U.S. Energy Information Administration (EIA).[13] EIA provides the number of residential, commercial, and industrial natural gas customers for each state. For the U.S. utilities in the top 35 comparators subject to the Tier 2 analysis, Guidehouse took a weighted average of the percent of residential natural gas customers as a total of residential, commercial and industrial natural gas customers for each state that a utility service territory covered. The underlying assumption for this process was that a utility’s percent of residential natural gas customers was the same as the percent of residential natural gas customers for the state/states its service territory covered, even if the utility does not service the entire state.

For the Canadian utilities, Guidehouse researched regulatory filings and annual reports to determine the percent of residential customers for each utility.[14]

For both the U.S. and Canadian utilities, Guidehouse cross-checked each utility’s website to ensure that residential natural gas customers are serviced. For utilities that were found to only service commercial or industrial customers, Guidehouse set the percent of residential customers equal to zero.[15]

For the Tier 2 criteria “Type of Heating Used by Customers”, Guidehouse used U.S.[16] and Canadian[17] census data. The Canadian census data was segmented by province and provided the percent of residents that use forced-air furnace heating. Guidehouse applied the same methodology and assumptions that were used to determine the percent of residential natural gas customers for the U.S. utilities to determine the percent of customers that use forced-air furnace heating for Canadian natural gas utilities. This meant assuming that the percent of residents that use forced-air furnace heating in each province is representative of the customers for the utilities that service those provinces, even if they do not service the entire province.

[11] Tier 2 criterion was weighted 1 and Tier 3 criterion was weighted 0.5.

[12] Strong was given a score of 3, moderate was given a score of 2 and weak was given a score of 1.

[13] Number of Natural Gas Consumers, U.S. Energy Information Administration. https://www.eia.gov/dnav/ng/ng_cons_num_a_EPG0_VN7_Count_a.htm

[14] Guidehouse was unable to locate this information for SaskEnergy; however, due to the similarities between SaskEnergy and EGI, Guidehouse escalated SaskEnergy to the Tier 4 analysis despite the lack of this information.

[15] This applied to Altagas, ATMOS Energy Corporation, Keyspan Energy d/b/a National Grid and Emera Energy.

[16] U.S. Census Bureau. Characteristics of New Housing. Historical Data. 2003-2017. https://www.census.gov/construction/chars/historical_data/

[17] Statistics Canada. Primary Heating Systems and Type of Energy. 2017. https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=3810028601

The U.S. heating census data was not provided on the state level; it was provided by groupings of the following regions:

- Northeast;
- Midwest;
- South; and
- West.

Guidehouse identified which region each utility was part of and assumed the percent of forced-air furnace households in the region was representative of the percent of forced-air furnace households in the utility service territory.

For the Tier 3 criterion, Guidehouse used data from the American Gas Association (AGA)[18] for the U.S. utilities' total customer count, total volume, and total revenue. The AGA provides this data for just the natural gas side of the company, in the case that a utility has both an electric and a gas business. For the Canadian utilities, Guidehouse searched utility websites, annual reports, and regulatory filings for this information. Guidehouse converted all revenue to USD[19] for comparison.

Utilities that had a rating of 8 or higher after the completion of the Tier 2 and Tier 3 filtering analysis were considered a pass and escalated to Tier 4. 23 utilities had a rating of 8 or higher based on the Tier 2 and Tier 3 filtering analysis. SaskEnergy had a rating below 8; however, this was due to lack of available information, not due to the utility being a poor comparator to EGI. Therefore, Guidehouse escalated SaskEnergy to the Tier 4 analysis, resulting in 24 total utilities that the Tier 4 analysis was applied to.

The Tier 4 analysis involved Guidehouse searching for regulatory documents pertaining to Gas Supply Planning procedures for each utility that passed Tier 1 to Tier 3 filtering. Regulatory documents were found using key word searches on public utility commission websites (U.S. utilities) and provincial regulatory websites (Canadian utilities). Guidehouse also completed general google searches using the same key words to find additional documentation. The following list of key phrases were used throughout the regulatory search:

- Natural gas supply planning
- Natural gas Design Day criteria
- Natural gas peak day demand
- Natural gas peak Design Day

[18] 2019 Ranking of Companies by Total Sales Customers. AGA Statistics Database. https://www.aga.org/contentassets/d68b868b7cd94ed2889b704b441ab469/1002totcust.pdf

[19] Based on the exchange rate of 1.28 on 2021-01-28.

Relevant documents were found for 13 of the 24 utilities that passed the Tier 1 to Tier 3 filtering criteria. After reviewing the documents, Guidehouse identified documents that provided sufficient details regarding the utilities Gas Supply Planning processes for 11 utilities. The 11 utilities and their relevant literature that is used throughout the subsequent sections of this report are listed below. Due to the varying degrees of information disclosed in the literature summarized below for the comparator utilities, the level of detail provided for each utility throughout section 3 to section 13 fluctuates.

- National Grid (Massachusetts and Rhode Island)
  - Rhode Island: Gas Long-Range Resource and Requirements Plan for the Forecast Period 2019/20 and 2023/24[20]
  - Massachusetts: November 1, 2020 through October 31, 2025 Long-Range Resource and Requirements Plan[21]

[20] National Grid, Narragansett Electric Company, Gas Long-Range Resource and Requirements Plan for the Forecast Period 2019/20 and 2023/24, Pursuant to the Joint Memorandum in RIPUC Docket No. 4816, July 2, 2019. http://www.ripuc.ri.gov/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20(7-2-19).pdf

[21] Boston Gas Company d/b/a National Grid, D.P.U. 20-132, November 1, 2020 through October 31, 2025 Long-Range Resource and Requirements Plan, October 30, 2020. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12842605

- National Grid (Downstate New York)
    - Natural Gas Long-Term Capacity Report for Brooklyn, Queens Staten Island and Long Island (Downstate New York) February 2020[22]
    - Natural Gas Long-Term Capacity Report for Brooklyn, Queens Staten Island and Long Island (Downstate New York) May 2020[23]
    - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, New York State Department of Public Service[24]
- Public Service Electric and Gas
    - In the Matter of the Exploration of Gas Capacity and Related Issues[25]
    - 2020/2021 Annual BGSS Commodity Charge Filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge[26]
- New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E)
    - NYSEG/RG&E 2020-2021 Winter Supply Plan[27]
- Consolidated Edison
    - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures – Supply/Demand Analysis for Vulnerable Locations [28]
- DTE Energy
    - In the matter of the Application of DTE Gas Company for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2019[29]

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[22] Natural Gas Long-Term Capacity Report for Brooklyn, Queens Staten Island and Long Island (Downstate New York) February 2020. https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Report_February_24_2020.pdf

[23] Natural Gas Long-Term Capacity Report for Brooklyn, Queens Staten Island and Long Island (Downstate New York) May 2020. https://www.nationalgridus.com/media/pdfs/other/ltng-supplementalreport.pdf

[24] Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, New York State Department of Public Service, 20-G-0131. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search

[25] In the Matter of the Exploration of Gas Capacity and Related Issues, Docket No. GO19070846, October 22, 2019, Public Service Electric and Gas Company, Reply to Comments. https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1214268

[26] In the Matter of Public Service Electric and Gas Company's 2020/2021 Annual BGSS Commodity Charge Filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge, Docket GR20060379, June 1, 2020 https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1221612

[27] NYSEG/RG&E 2020-2021 Winter Supply Plan, Case 20-M-0189, July 15, 2020. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B36C8F36C-6F37-498A-8BAD-99F70168D3BE%7D

[28] Case 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures – Supply/Demand Analysis for Vulnerable Locations, Consolidated Edison, July 17, 2020. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search

[29] In the matter of the Application of DTE Gas Company for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2019, MPSC Case No. U-18412, September 18, 2018, https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000086HOyAAM

- CenterPoint Energy Minnesota Gas
  - CenterPoint Energy 's Request for Change in Demand Units [30]
- National Fuel Gas Distribution
  - National Fuel Gas Distribution Corporation Supply and Demand Analysis Related to Service Areas within known Supply Constraint Vulnerabilities [31]
- Wisconsin Power & Light
  - Wisconsin Power and Light Company's Gas Supply Plan for the Period Beginning November 1, 2020[32]
- Northern States Power Company
  - Gas Recovery Plan [33]
- EPCOR Natural Gas Limited Partnership
  - EPCOR Southern Bruce Gas Supply Plan: 2020-2023[34]

[30] CenterPoint Energy 's Request for Change in Demand Units, Docket No. 18-462, July 2, 2018. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B00DD5C64-0000-CD1F-99AF-13501BF36511%7D&documentTitle=20187-144460-01

[31] National Fuel Gas Distribution Corporation Supply and Demand Analysis Related to Service Areas within known Supply Constraint Vulnerabilities, Case 20-G-0131, July 17, 2020. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search

[32] Wisconsin Power and Light Company's Gas Supply Plan for the Period Beginning November 1, 2020, 6680-GP-2020, July 9, 2020. https://apps.psc.wi.gov/pages/viewdoc.htm?docid=393346

[33] Northern States Power Company, a Wisconsin corporation Case No. U-20820, Gas Recovery Plan, December 22, 2020. https://mipsc.force.com/sfc/servlet.shepherd/document/download/069t000000HXJnzAAH?operationContext=S1

[34] EPCOR Southern Bruce Gas Supply Plan: 2020-2023, EB-2020-0106, June 2020. https://www.rds.oeb.ca/CMWebDrawer/Record/679884/File/document

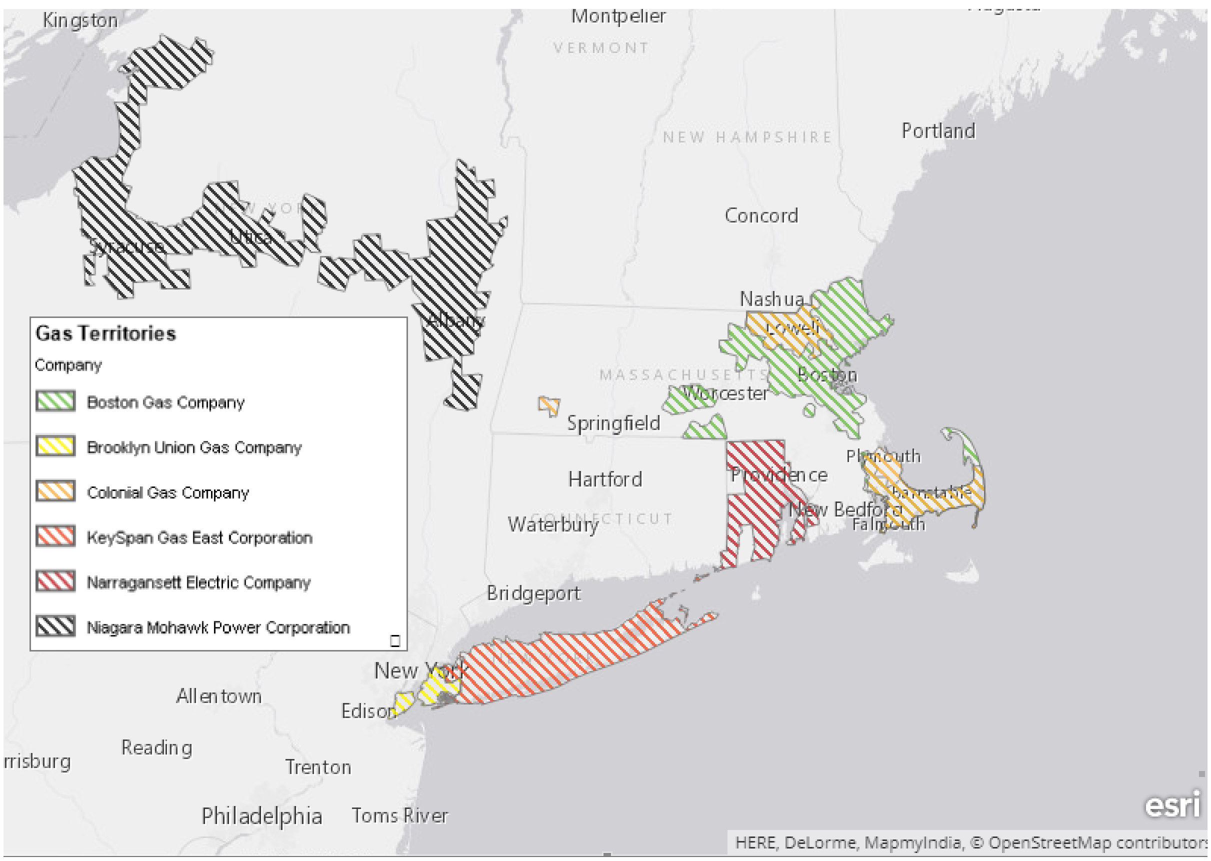
3. National Grid - Boston Gas and Narragansett Electric[35,36]

3.1 Summary

National Grid owns and operates electric and gas distribution networks in Massachusetts, New York, and Rhode Island. The company's gas distribution networks in these jurisdictions serve approximately 3.6 million customers. The company's natural gas operating subsidiaries include Boston Gas Company (MA), Brooklyn Union Gas Company (NY), Colonial Gas Company (MA), KeySpan Gas East Corporation (NY), Narragansett Electric Company (RI) and Niagara Mohawk Power Corporation (NY).

As outlined in National Grid's Long-Range Resource and Requirement Plans, Boston Gas and Narragansett Electric are the only subsidiaries to use a probabilistic approach to Design Day and serve Boston and Rhode Island.

Figure 3-1: National Grid U.S. Gas Service Territories



The other National Grid natural gas utilities use the set temperature approach and are not based on a probabilistic "once-in-x years" methodology as discussed in Section 4.

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[35] National Grid, Narragansett Electric Company, Gas Long-Range Resource and Requirements Plan for the Forecast Period 2019/20 and 2023/24, Pursuant to the Joint Memorandum in RIPUC Docket No. 4816, July 2, 2019. http://www.ripuc.ri.gov/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20(7-2-19).pdf

[36] Boston Gas Company d/b/a National Grid, D.P.U. 20-132, November 1, 2020 through October 31, 2025 Long-Range Resource and Requirements Plan, October 30, 2020. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12842605

3.2 Approach

In this section, Guidehouse discusses the probabilistic approach to Design Day used by National Grid for its gas utilities serving Boston and Rhode Island, where the Design Day standard is based on once-in-35 years probability of occurrence of extreme weather conditions (i.e., Design Day temperatures) in Boston and once in 58.92 years in Rhode Island. In the Boston Gas and Rhode Island service territories, the Company conducts a benefit-cost analysis that considers cost and risk of an outage compared to levels of investment in infrastructure and other solutions as part of its gas supply planning process.

The Companies define the purpose of a Design Day standard as the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system.

The Company's forecast methodology supports its supply planning goals of ensuring that: (1) its resource portfolio maintains sufficient supply deliverability to meet customer requirements on the coldest planning day ("Design Day"); and (2) it maintains sufficient supplies under contract and in storage (underground storage, LNG and propane) to meet customers' requirements over the coldest planning year ("design year").

In the Boston Gas 2020 Long-Range Resource and Requirements Plan for the forecast period 2020/21 to 2024/25 filing[37],the Company defines its Design Day standard at 78 daily effective degree days (EDD) with a probability of occurrence of once in 35.32 years, as a result of its on-going review of planning standards.

In Rhode Island, the Design Day standard is 68 heating degree days (HDD) with a once in 60-year probability of occurrence. This equates to a Design Day average temperature of -3 degrees Fahrenheit (approx. -19 C), 60 years.

To confirm its Design Day selection, National Grid-Boston Gas and Narragansett Electric deploy the following approach:

1. Perform a statistical analysis of the coldest days recorded over a historical period.

2. Conduct a cost-benefit analysis to evaluate the cost of maintaining the resources necessary to meet Design Day demand versus the cost to customers of experiencing service curtailments.

3. Identify a design-day standard that would maintain reliability at the lowest cost.

3.3 Methodology

National Grid uses the following methodology to execute its approach

1. **Calculate the Design Day:**

[37] https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12842605

- Identify the coldest day that occurred in each calendar year from 1980 to 2019 (40 years). For the Boston Gas Supply Plan, the Company selected the Boston Logan Airport weather station because of its central location relative to the Company's service territory. In Rhode Island, evaluate 40 years of weather at the T.F. Green Airport weather stations.

- Performance of a statistical analysis to determine the standard deviation to determine the Design Day

2. Conduct cost-benefit analysis

In both the Boston Gas and Rhode Island gas supply plans, National Grid identifies the potential costs that could be incurred in the event of a supply disruption. The company notes that "there are several types of damages that customers could experience". These include the cost of re-lighting residential customer appliances and repairing damages from freeze-ups. For commercial customers, potentially economic damages could be incurred from loss of production during a supply disruption. To address the potential damages that could occur in the event of a supply shortfall, the Companies use the following approach to determine the probability of an actual day exceeding the Design Day standard; identify the potential shortfall in gas supply; and compare the cost of additional supply to the benefit of avoiding a system disruption:

a. Identify the cumulative probability distribution and the frequency of occurrence of EDD level greater than the mean peak day.

b. Determine the projected shortfall of supply (delta supply) that would occur using the following formula:

   *[Delta Supply / (Heating Increment/ Number of Customers)*EDD]*

c. Incorporate the EDD levels and the associated Delta Supply to estimate the costs associated with maintaining adequate supply deliverability at the EDD levels.

   i. A scenario approach is used to calculate the additional supply costs with one scenario (low-upgrade cost) incorporating the cost of additional LNG vaporization capacity and the second scenario (high-upgrade cost) based on the cost of adding 365-day interstate pipeline service.

   ii. Other potential options fall in between these low and high cases

d. Compare the cost of maintaining adequate throughput capacity and the benefit of avoiding damage costs that would be incurred in relation to customer premises.

3. Identify a design-day standard that would maintain reliability at the lowest cost.

a. Evaluate the cost/benefit trade-off of maintaining adequate throughput capacity and the benefit of avoiding damage costs.

b. National Grid selected a Design Day standard that reflects a frequency of occurrence of one in 35.32 years and once in 58.92 years in Boston and Rhode Island, respectively. This represents the probability of occurrence of an actual EDD exceeding the Design Day standard that would result in costs of maintaining adequate throughput capacity exceeding the benefit of avoiding damage costs.

The Design Day standard becomes a critical input into the calculation of Design Day sendout requirements and informs the Company's supply planning to meet customer requirements

Design of the Resource Portfolio

The calculation of the Design Day is a critical component of the Companies' gas supply resource plan. The Design Day translates into a planning standard for the development of a least-cost, reliable supply portfolio. The Companies uses the following five step approach to forecast customer demand, identify the Design Day planning standards and, lastly, determine customer requirements under design day weather conditions.

1. Forecast Retail Demand Requirements

Retail demand requirements are based on customer billing data, which is available by rate class and by month. The Company uses a series of econometric models to develop a forecast of retail demand requirements for traditional markets (i.e., residential heating, residential non-heating, and commercial and industrial ("C&I") customers). The forecast of retail demand requirements for traditional markets is summed to determine the total retail demand requirements over the forecast period. This forecast of retail demand is disaggregated into monthly billed and unbilled volumes and, hence, can be calendarized for supply planning purposes.

2. Develop Reference Year Sendout Using Regression Equations

The daily values of the Company's wholesale SENDOUT[38] in the reference year (April 2012 – March 2013) serves as the basis of allocating the monthly retail demand forecast to the daily level. Because actual sendout data for the reference year is a function of the weather conditions experienced in that year, the Company develops this allocator for sendout using regression equations to normalize the sendout in the reference year based on normalized weather data

3. Normalize Forecast of Customer Requirements

The Company's monthly retail demand forecast is allocated to the daily level based on the use of its daily wholesale sendout regression equation and its normal daily heating degree day data. This step sets the Company's total normalized forecast of customer requirements over the ten-year forecast period.

[38] SENDOUT ® is a proprietary linear program model provided by ABB to determine the adequacy and deliverability of a gas supply portfolio to meet forecasted gas supply requirements and to identify shortfalls as well as operational constraints

4. Determine Design Weather Planning Standards

The Company performs an analysis to determine the **appropriate Design Day and design year** planning standards for the development of a least-cost reliable supply portfolio over the forecast period.

5. Determine Customer Requirements Under Design Weather Conditions

Using the applicable Design Day and design year weather planning standards, the Company determines the design year sendout requirements and the Design Day sendout requirements. These design sendout requirements establish the Company's resource requirements over the forecast period.

4. National Grid – Downstate New York[39,40]

4.1 Summary

National Grid provides natural gas to 1.9 million customers throughout Brooklyn, Queens, Staten Island and Long Island and the Company defines these service territories as Downstate New York (NY).

National Grid, in its Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY Report"), released in February 2020, defines the Design Day as the level of gas delivery required to service all our customers during a cold weather event that occurs on an infrequent basis, typically only once every 40 years. This Design Day is used to build the Company's long-term capacity models.

In Downstate NY, the Design Day is based on a 24-hour period that averages 0 degrees Fahrenheit in Central Park. It is not clear from National Grid's reports how the 0 degrees Fahrenheit temperature was selected, but National Grid notes that the last day that met the Design Day criteria was February 9, 1934.

4.2 Approach

National Grid notes in its Downstate NY Report that the Company is required to ensure sufficient capacity on a peak day during peak hours, e.g., when maximum gas is consumed as customers turn up their thermostats, cook, and use gas for hot water heating. Gas customers typically do not consume the same volume of gas each hour, i.e., in even 1/24th increments. In reality, customers tend to use more gas in the early morning hours, typically 6 – 10 a.m., and again in the evening from 4 – 8 p.m.

To ensure adequacy of delivery capacity and supply to meet the needs of customers during those time periods, National Grid examines the needs during these peak times by using a Design Hour standard.

The Company uses the Design Hour requirement to perform various analyses necessary for distribution system operations (e.g., regulator pressure settings, LNG requirements) and capital planning. Moreover, the Company has used the Design Hour requirement for some short-term gas supply planning decisions.

National Grid defines the Design Hour as 5% (i.e., 1/20th) of the Design Day Standard. The Company uses the same Design Hour Standard in Massachusetts and Rhode Island for system planning.

4.3 Methodology

In May 2020, National Grid released a supplemental report to the Long-Term Capacity Report in which the Company addressed the use of the probabilistic method and discussed the impact on

[39] Natural Gas Long-Term Capacity Report for Brooklyn, Queens Staten Island and Long Island (Downstate New York) May 2020. https://www.nationalgridus.com/media/pdfs/other/ltng-supplementalreport.pdf

[40] Natural Gas Long-Term Capacity Report for Brooklyn, Queens Staten Island and Long Island (Downstate New York) February 2020. https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Report_February_24_2020.pdf

gas supply planning, particularly Design Hour requirements. The Company observers "When considering all of these potential impacts – temperature, wind chill, Design Day vs. Design Hour, and any potential considerations for forecast error or operating margin/contingency – it is National Grid's conclusion that there are too many factors to warrant changing the analysis without a more detailed study done in conjunction with other impacted parties and stakeholders. Therefore, our analysis considering the gap between demand and supply and comparing different options for closing that gap and meeting the needs of Downstate NY continues with the 0°F Design Day standard. Going forward, National Grid believes there is an opportunity to review Design Day standards with the NY PSC as part of the recently announced natural gas supply planning proceeding[41].

Guidehouse observes that National Grid is referring to a regulator proceeding on gas planning procedures (New York State Department of Public Service Case 20-G-0131). In this proceeding, the Staff of the New York State Department of Public Service made the following recommendations related to a gas utility's demand forecast:
"The demand forecast must include a weather-adjusted back cast using actual weather conditions to assess the load that would have been experienced had temperatures dropped to the Design Day level. Forecasts of future load should be consistent with short term weather and forecasted usage determination techniques and include adjustments for energy efficiency, electrification, demand response, NPAs (Non-Pipe Solutions), and other external impacts (e.g.,COVID-19).To enhance transparency in the planning process, the forecast must contain a geographical analysis with enough granularity to clearly identify locations of anticipated localized demand growth to allow for adequate planning. For the LDCs serving the downstate metropolitan area including New York City, Westchester County, and Long Island, the LDCs should separately forecast at least each of the five Boroughs of New York City, and the Counties of Westchester, Nassau, and Suffolk."

[41] Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, New York State Department of Public Service, 20-G-0131.
http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search

5. Public Service Electric and Gas[42,43]

5.1 Summary

Public Service Electric and Gas Company (PSE&G) is an electric and gas utility and is the largest subsidiary of Public Service Enterprise Group. PSE&G serves 2.3 MM electric customers and 1.9 MM gas customers, in New Jersey.

As outlined in PSE&G's 2020/2021 annual Basic Gas Supply Service Charge, PSE&G uses the set temperature approach to establish its Design Day requirements. Distribution facilities are designed to meet the estimated maximum hour demand on a day with a mean temperature of 0°F and with Newark Airport as the measuring base.

5.2 Approach

PSE&G's natural gas distribution facilities are designed to meet the estimated maximum hour demand on a day with a mean temperature of 0°F and with Newark Airport as the measuring base. This is detailed in the Company's 2020/2021 annual Basic Gas Supply Service Charge filing for its residential gas customers that was filed on June 1, 2020.

The Company's gas supply portfolio Gas supplies are designed to meet the estimated maximum daily as well as maximum hourly demand. The maximum daily sendout forecast process consists of:

- Estimating the relationship between weather and firm daily sendout,
- Extrapolating that relationship to determine the current level of daily sendout at 0 degrees if no day that cold appeared in the model estimation data,
- Forecasting future maximum daily sendout levels based on the current estimated level

5.3 Methodology

PSEG does not disclose in its publicly available filings and testimony how the Design Day temperature is calculated.

[42] In the Matter of the Exploration of Gas Capacity and Related Issues, Docket No. GO19070846, October 22, 2019, Public Service Electric and Gas Company, Reply to Comments. https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1214268

[43] In the Matter of Public Service Electric and Gas Company's 2020/2021 Annual BGSS Commodity Charge Filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge, Docket GR20060379, June 1, 2020 https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1221612

6. New York State Electric & Gas and Rochester Gas & Electric[44,45]

6.1 Summary

New York State Electric & Gas (NYSEG) and Rochester Gas & Electric (RGE&E) are two natural gas utilizes in NY serving approximately 270,000 and 320,000 gas customers, respectively. Both companies are owned by Avangrid.

NYSEG and RGE&E both use the probabilistic method as identified in the Companies' 2020-2021 Winter Supply Plan.

6.2 Approach

NYSEG's design weather pattern for planning utilizes weather data for seven (7) NYSEG load areas, while RG&E is a single load area. The companies also utilize GasDay, which is a vendor-supplied software application that delivers customized forecasting models trained on historical weather data. GasDay is used for near-term forecasting, up to seven (7) days in advance. The Companies uses 40 years of weather data to calculate and estimate of the Design Day needs across the service territories. The Companies use a five (5)-year planning horizon because pipeline capacity commitments are typically for a minimum of five (5) years.

6.3 Methodology

The Companies conduct a variety of analyses to validate the Design Day demand levels for each operating area.

1. The Design Day analysis evaluation is based upon regression analyses performed on actual winter month usage and associated HDDs to determine base and heat factors and an associated Design Day estimate.

2. Extrapolation utilizing the heat factor from (1) above multiplied by (Design Day HDD minus the actual HDD) plus the actual metered load. Then the average, maximum and minimum extrapolated design loads are reviewed.

3. Utilization of total non-daily metered winter heat load divided by the total HDDs multiplied by Design Day HDD + baseload factor provides a third Design Day demand estimate.

[44] NYSEG/RG&E 2020-2021 Winter Supply Plan, Case 20-M-0189, July 15, 2020. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B36C8F36C-6F37-498A-8BAD-99F70168D3BE%7D

[45] NYSEG/RG&E 2018-2019 Winter Supply Update Plan

7. Consolidated Edison New York Inc[46]

7.1 Summary

Con Edison provides natural gas services to over 1.1 million customers in the state of New York. It manages a transportation and distribution system with approximately 4,400 total miles of gas main and approximately 376,000 service pipes. Con Edison transports over 340 million dekatherms (Dth) of natural gas per year.

There are seven gate stations from four different pipeline companies that supply Con Edison's transmission facilities. Additionally, there are approximately 100 regulators supplying gas from the transmission system into the distribution system and 51 remote operated valves (ROVs). New York Facilities (NYF) Systems[47] is a larger network that Con Edison's systems are connected to through two bi-directional metering stations and five metered take-off locations. The following interstate pipelines service NYF System.

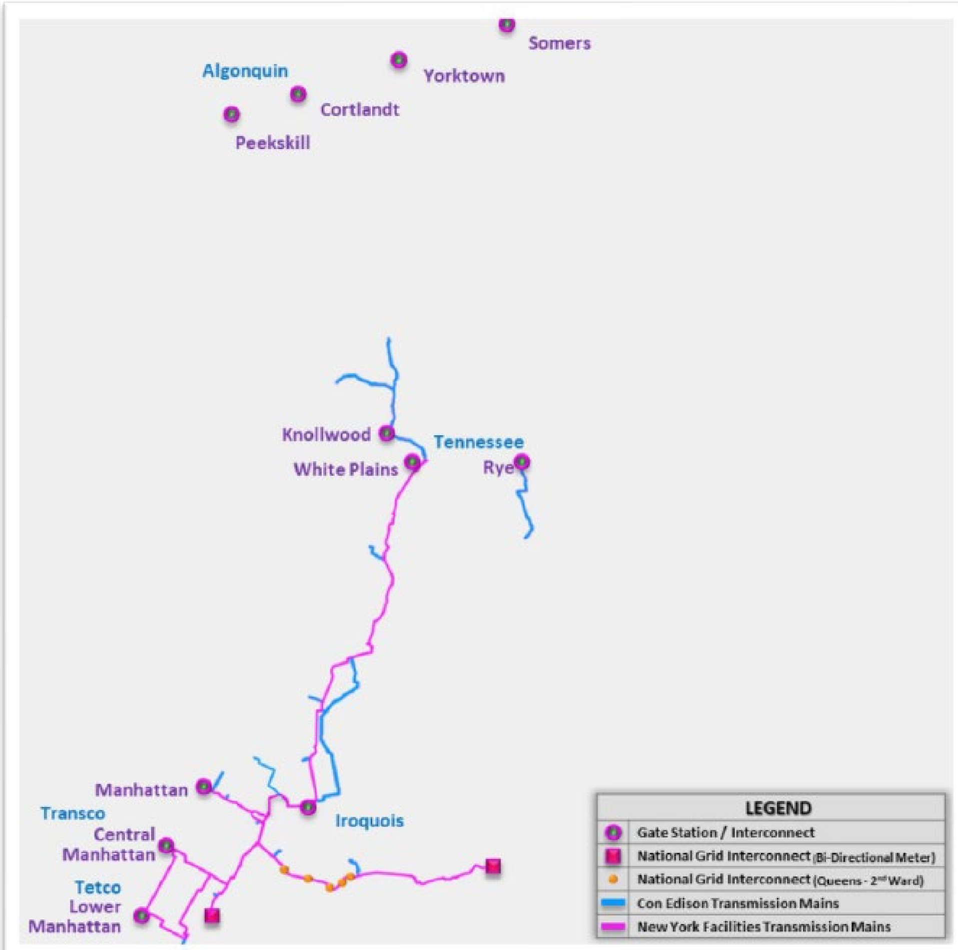
- Transco,
- Texas Eastern; and
- Tennessee and Iroquois.

Figure 7-1 below shows Con Edison's transportation and distribution system.

[46]Case 20-G-0131 - Proceeding on Motion of the Commission in Regard to Gas Planning Procedures – Supply/Demand Analysis for Vulnerable Locations, Consolidated Edison, July 17, 2020. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search

[47] NYF Systems is jointly operated by Con Edison, National Grid Metro and National Grid Long Island.

Figure 7-1 Con Edison's Transportation and Distribution System



In 2020, Con Edison disclosed its approach and methodology to determining its Design Day criteria, due to the New York State Department of Public Service's Proceeding on Motion of the Commission in Regard to Gas Planning Procedures. In this filing, Con Edison indicated it uses a set temperature approach. This is summarized in more detail in the following sections.

7.2 Approach

Con Edison (the Company) uses a 10-year forward projection of both expected peak demand and existing supply capabilities, applied to hydraulic flow models of the Companies' gas systems to predict future supply-demand gaps.[48] Gaps identified fall into two categories:

1. Those caused by inadequate levels of interstate pipeline capacity; and

2. Those created by the inability of the existing distribution system to deliver the available supplies to the location of the new demand.

[48] Orange and Rockland uses the same approach as Con Edison, and it is outlined in the same regulatory document.

The Company developed an existing supply capability outlook by reviewing publicly available pipeline contract information from all pipelines servicing the Company's service territories. They then use this data to predict the market potential for procurement of incremental delivered services.

7.3 Methodology

The Company developed a firm gas peak demand forecast following two major steps:

1. Analyzing the Weather Adjusted Peak ("WAP") at design weather in the form of Temperature Variable ("TV"), currently a TV of 0°F, for the previous winter experience, and

2. Estimating the net incremental growth going forward.

The TV is used in calculating and forecasting future system peak demands as follows, taking into account extreme winter weather conditions (i.e., sustained low temperatures over two Gas-Day periods):

- The gas day average ("GDA") temperature is a 24- hour arithmetic average starting at 10 AM using the Central Park National Weather Station dry bulb temperature[49]. The formula for calculating the system TV on a daily basis incorporates two days' worth of GDAs.
- For Con Edison, the current day's TV is weighted at 70% of the current day's GDA and 30% of the previous day's GDA.
- For Orange and Rockland, the current day's TV is weighted at 80% of the current day's GDA and 20% of the previous day's GDA. Con Edison and Orange and Rockland use a weather reference of 0°F TV for design conditions.
- Con Edison also considers average Wind Speed ("WS") as a variable in their weather adjustment processes.

Using TV and WS as reference points, regression analyses are performed to determine the weather adjusted system firm peak demand. Typically, a pooled linear regression is developed using up to five years of peak-day demand TV and WS data for the winter season. The Company will determine whether to consider a single winter's data or a pooling of several winters' data and whether to apply a linear or polynomial regression based on how well the statistical modeling aligns with actual observations.
Areas that contribute to load growth in the forecast are:

- Large new construction
- Small residential construction
- Net transfers
- Oil-to-gas conversions
- Steam-to-gas conversions

[49] For Orange and Rockland the Spring Valley National Weather Station is used.

Areas that contribute to load reduction in the forecast are:

- DSM
- Natural conservation
- Electrification

The Company designed and planned its natural gas system to a 0°F TV for firm service. The TV is calculated using portions of two consecutive days of extreme cold weather conditions because the percent weightings on the two consecutive gas days provides the best correlation of temperature to customer load.

The design basis for Con Edison system is N-0[50] not N1, from a reliability/operational security design, do not have any loss of load expectation, do not include reserve margins to accommodate any loss of supply due to equipment issues on a peak day, cannot operate safely with diminished system operating pressures, and rely on transportation from distant supply sources not under the Company's direct control. In summary, in contrast to the electric system which maintains a 19% reserve margin, 100% of gas supply resources are assumed to be available in order to meet peak Design Day customer demand requirements.

[50] N-0 = System State or the number of elements that can fail. N-1 means the system can meet demand even with loss of its largest supply unit. Under this analogy, a gas interstate pipeline, compressor station, and gate station are likened to an electric generator or transmissions feeder.

8. DTE Gas[51]

8.1 Summary

DTE Gas, which is a subsidiary of DTE Energy Company, services approximately 1.2 million residential, commercial, and industrial customers throughout the state of Michigan.

In 2019, DTE Gas filed before the Michigan Public Service Commission for the authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous account authority. In this filing, DTE Gas indicates it uses a Design Day approach rather than a historical peak day approach because “a historical peak day may not reflect consumption expected in severe cold weather because, on that peak day, temperatures may have been above the design conditions”.

8.2 Approach

The design peak day volume calculation is determined annually for gas cost recovery purposes to ensure DTE Gas’s retail customer Gas Cost Recovery (GCR), Gas Customer Choice (GCC) and end-user transportation markets can be physically served even with the coldest historical temperatures that have been experienced in its service areas.

The following section outlines DTE Gas’s Design Day methodology in more details, based on its 2019 filing.

8.3 Methodology

The design peak day is defined as the consumption expected on a day with an average temperature of -6 degrees Fahrenheit. Customer mix impacts the design peak day volume as each class has a different sensitivity to temperature. In the GCR process, key operational factors are considered to ensure the Company’s ability to reliably serve its customers. These variables include retail market size, storage capability, contractual obligations, flowing supply, and potential weather effects. Given these factors, the Company calculates the optimal operating plan for the worst possible weather conditions to ensure supply reliability. This plan guides the Company’s design peak day calculation.

Peak day design conditions are evaluated on an annual basis. DTE states that design peak day volume can change if the temperatures experienced warrant changing the design. For example, based on January 30, 2019, (in the Detroit/Ann Arbor service region only), the actual experienced temperature throughout the day led DTE to adjust its end of January design temperature for the Detroit area from -4°F to -6°F. All other regions did not experience temperatures that exceeded the previous Design Day temperatures and thus were not adjusted.

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[51] In the matter of the Application of DTE Gas Company for approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 months ending March 31, 2019 MPSC Case No. U-18412, September 18, 2018. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000086HOyAAM

9. CenterPoint Energy Minnesota Gas[52]

9.1 Summary

CenterPoint Energy Minnesota Gas (CenterPoint Energy) is gas utility that services customers approximately 1.4 million customers in Minnesota. In 2018, CenterPoint Energy supplied 58 million Dth of natural gas to its customers in Minnesota.

As outlined in its 2018 Request for Change in Demand Units filing, CenterPoint Energy uses the probabilistic method to establish its Design Day requirements. It calculates its Design Day customer usage at the upper level of the 95% confidence interval, which limits the likelihood of the actual usage being above the estimate to a 2.5% chance. CenterPoint believes this is necessary due to Minnesota's cold climate.

9.2 Approach

The methodology outlined below is based on CenterPoint Energy's Request for Change in Demand Units. CenterPoint Energy's 15-year contract with Northern Natural Gas for transportation service ended on October 31, 2019; therefore, it began reviewing its need for additional pipeline transportation capacity to meet current and future customers' demand.

CenterPoint Energy disclosed its Design Day Model for the purposes of that filing, and it is summarized below.

9.3 Methodology

CenterPoint Energy's Design Day modelling process is completed by adding the results of the following two regression models together:

1. Traditional Design Day Model
2. Customer Migration Design Day Model

The traditional firm Design Day forecast is based on the following variables:

- Daily firm usage data from all winter days for the past six heating seasons,
- Count of firm customers,
- HDDs, and
- The square of HDDs as independent variables to account for the non-linear relationships between HDD and usage.

This model estimates the expected use-per customer ("UPC") at various levels of HDD. CenterPoint Energy calculates the UPC level from the model at the upper level of the 95%

[52] CenterPoint Energy 's Request for Change in Demand Units, Docket No. 18-462, July 2, 2018. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B00DD5C64-0000-CD1F-99AF-13501BF36511%7D&documentTitle=20187-144460-01

confidence interval to limit the likelihood of the actual UPC being above the estimate to a 2.5% chance.

For the traditional firm customers UPC modelling, CenterPoint Energy removes the customers usage from the total firm daily sales for those who had converted to firm sales service in the historical lookback period for the dataset. This ensures the data set is consistent with all five previous winter seasons.

The customer migration Design Day model is based on six years of daily sales data. Regression models, similar to those used for the traditional firm customers, are used to estimate expected use under Design Day conditions. CenterPoint Energy uses actual service election to estimate sales service requirements. The Design Day estimate for customers expected to use CenterPoint Energy’s entitlement for recently converted customers is added to the traditional forecast.

CenterPoint Energy can then estimate the amount of entitlement the various customer groups will need on Design Day, from the model at the upper level of the 95% confidence interval. This allows them to ensure they have enough capacity to deliver gas when the temperature is approaching a Design Day scenario. The likelihood the actual use per customer being above the Design Day estimate is 2.5% and CenterPoint Energy has deemed the overall 2.6% reserve margin reasonable.

10. National Fuel Gas Distribution Corporation[53]

10.1 Summary

National Fuel Gas Distribution Corporation (the Company) sells or transports natural gas to over 740,000 customers in Western New York (i.e., the cities of Buffalo, Niagara Falls, and Batavia) and Northwestern Pennsylvania. As outlined in its 2020 Supply and Demand Analysis Related to Service Areas within known Supply Constraint Vulnerabilities, the Company uses a set temperature approach for determining its Design Day criteria.

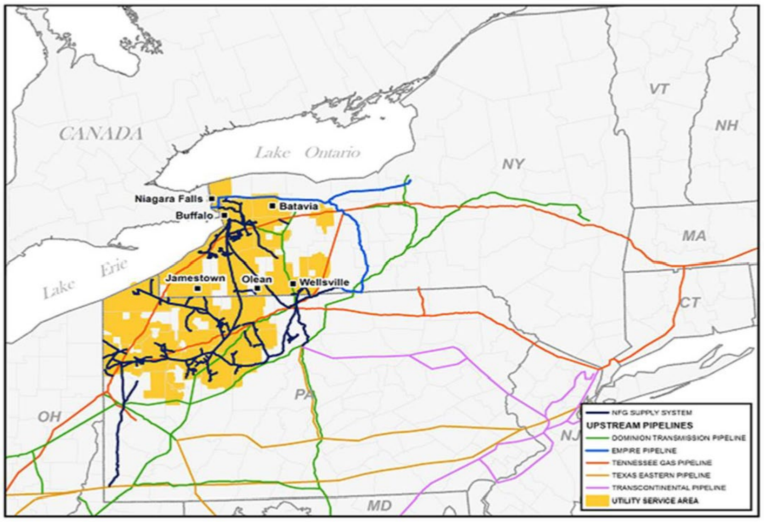
The Company maintains contracts for firm transportation and storage capacity on National Fuel Gas Supply Corporation (Supply) and on the following pipelines upstream of Supply:

- Dominion Energy Transmission (Dominion)
- Empire Pipeline (Empire)
- Honeoye Storage (HSC)
- Tennessee Gas Pipeline (TGP)
- Transcontinental Gas Pipeline (Transco)

95% of the Company's deliveries come from the pipelines upstream of Supply and the other 5% of deliveries are sourced from production attached directly to the Company's system. The Supply is responsible for receiving gas from pipelines upstream of its system, for making redeliveries to the Company's non-contiguous delivery systems, and for transmitting its gas supplies from Supply's underground storage fields dispersed in and around the Company's service territory. When there is low customer demand, the Company uses its storage fields to hold the exceeding supply of gas. This enables the company to maintain a high load factor on its upstream pipeline capacity, allowing lower pipeline costs and a more favorable purchasing pattern from suppliers. Figure 10-1 below shows the Company's distribution service territory and its upstream pipelines.

[53] National Fuel Gas Distribution Corporation Supply and Demand Analysis Related to Service Areas within known Supply Constraint Vulnerabilities, Case 20-G-0131, July 17, 2020. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search

Figure 10-1 National Fuel Gas Distribution Corporation Distribution Service Territory and Upstream Pipelines



10.2 Approach

The gas system planning analysis is done by the Company in multiple stages:

1. Assessing Expected Demand: A peak demand forecast is done so the Company can ensure it can maintain gas deliveries to its customers during several day cold snaps, the coldest day, and the highest use peak hours by developing design planning criteria to meet demand on a Design Day.

2. Supply Portfolio: Identify the portfolio of supply resources that are available to serve a particular location.

3. Transmission and Distribution System Configurations: Use flow modeling to evaluate the delivery of supplies to meet customer demand throughout the transmission and distribution system.

4. Potential Solutions: Solutions evaluated to resolve any vulnerable locations (i.e., a portion of the system where gas may not be able to be delivered safely and reliably within the next five years).

The methodology behind this approach is outlined in the subsequent section and is based on the Company's Supply and Demand Analysis Related to Service Areas within known Supply Constraint Vulnerabilities.

10.3 Methodology

The Company determines its Design Day requirements by calculating the daily natural gas supply requirements that would occur in the month of January if the Company's New York service territory experienced extremely cold weather on a day that produces 74 heating degree days. National Oceanic and Atmospheric Administration (NOAA) records identify January as the coldest month in the Company's service territory and the Company uses this as the basis for its analysis. The average day in January produces approximately 40 HDDs in the Company's New York service territory.

When the Company designs an energy supply strategy, the capacity asset portfolio must meet the following requirements:

1. Be able to meet a Design Day of 74 heating degree days,

2. Service firm customers for a winter period that is 15% colder than normal, and

3. Meet year-round demand.

For the procurement of capacity and supplies the Company serves two types of customers:

1. Group 1: Sales service customers and critical service transportation customers (i.e., customers that use 5,000 Mcf per year or less and those that use more than 5,000 Mcf per year but serve human needs such as hospitals and nursing homes), and

2. Group 2: Non-critical transportation customers that use more than 5,000 Mcf per year and do not serve human needs.

For Group 1 customers, the Company contracts for firm pipeline transportation and storage capacity to meet the full requirements of up to 74 HDD. For Group 2, the Company only procures enough capacity to equal 12 HDD. For non-critical transportation customers, the Company does not release its capacity to meet requirements of such customers when they use more gas than they were directed to bring to the system on a given day. Instead, the customers are required to procure their own firm upstream pipeline capacity in an amount equal to 62 HDD.

To ensure reliability for its gas supply in the event of well and pipe freeze-offs during extreme cold periods and on a Design Day, the Company also procures capacity to meet 35% of its forecasted total receipts from local production that delivers directly into its system for sales and transportation customers. The Company also maintains contingency capacity as a safety factor in case of unforeseen events occurring during the coldest days of the year or if actual demand exceeds the Design Day forecast.

The Company's distribution system is evaluated regularly to ensure safe operation and reliability. The Company uses System Reliability Reports to identify operational issues on piping systems, and at Metering & Regulating (M&R) stations. Some issues that the System Reliability Reports might find are gas quality issues, pipe washouts, pipe exposures, and other potentially hazardous conditions.

Additionally, the Company has a hydraulic model of its entire distribution system that allows it to create and update models using actual system pressure and flows. Through this, the Company is able to create an accurate representation of operating conditions that it can design and balance to simulate a 74 HDD. The use of these models ranges from identifying solutions to fix low pressure areas, determine the impact of proposed work on the overall system operation, and to stimulate different operating scenarios.

The Company assesses the adequacy of the capacity and supply resources available to meet its Design Day demands for past and future winters. This is done by designating specific market areas within New York to evaluate Design Day demands and identify the specific pipeline and storage assets necessary to serve that demand. After each winter, a review is done that assesses the peak day actual throughput for each market to determine if the peak day throughput exceeded previous peak throughputs. Then, observed actual peak day throughput data is extrapolated to simulate throughput if the average daily temperature achieved a planned Design Day of 74 HDD, or -9 degrees Fahrenheit.

11. Wisconsin Power and Light[54]

11.1 Summary

Wisconsin Power and Light (WPL) is a subsidiary of Alliant Energy. Alliant Energy serves approximately 420,000 natural gas customers in the Midwest. In 2020, WPL filed its Annual Gas Supply Plan for the period beginning November 1, 2020. This regulatory filing is referenced throughout the following sections that describe WPL's set temperature approach for its Design Day forecast.

11.2 Approach

WPL's Design Day forecast follows three key steps to forecast firm customer Design Day throughput in Wisconsin to ensure it has sufficient supply to meet the needs of its firm Wisconsin customers under extreme weather conditions.

1. Calculate the following model inputs:
    a. Meter forecasts,
    b. Daily throughput, and
    c. Design day weather.
2. Estimate firm Design Day throughput, and
3. Compare forecast to historical data.

The following section outlines this approach to in more detail, based on the information outlined in WPL's Annual Gas Supply Plan.

11.3 Methodology

For meter forecasts, WPL forecasts additional new meters from pipeline expansions and baseline meter growth. For the additional new meters from pipeline expansions, WPL forecasts meters by counting meters geographically near recent expansions and applying historical natural gas adoption rates to the projected expansion projects. For baseline meters, WLP uses regression models that incorporate growth trends, monthly variation and indicators for one-time events. The two forecasts are added together to provide a total meter forecast.

Daily throughput is calculated using system gas and transport usage for the historical lookback period of 5 years. WLP subtracts usage from the transport and interruptible customers, because it does not provide firm service to those customers. When daily firm throughput is divided by the number of meters the result is daily throughput per meter.

Design day weather is determined through a set temperature method. WLP assumes a Design Day of 86 HDD and an average wind speed of 8.7 MPH. These conditions are based on the

[54] Wisconsin Power and Light Company's Gas Supply Plan for the Period Beginning November 1, 2020, 6680-GP-2020, July 9, 2020. https://apps.psc.wi.gov/pages/viewdoc.htm?docid=393346

coldest day on record in Wisconsin, which was on February 2, 1996. Hourly weather data from the city of Madison for the 24-hour coldest day period, ending at 9 am, is used to compute gas day weather. The timing of the gas throughput is matched to the overnight temperatures and then using the gas day weather, daily HDD care calculated using a base of 65 degrees Fahrenheit.

WLP removes days that are not representative of Design Day conditions to reduce variability. This is days such as weekends, holidays, and days with average temperature over 50 degrees Fahrenheit.

The resulting daily firm throughput per meter is regressed against daily HDD and average daily wind speed values. These values use Ordinary Least Squares. The regression model uses the Design day HDDs, average wind speed, and number of meters to forecast the Design Day throughput.

The final step of WPL's methodology is to compare the forecast to historical data. The throughput for the peak days of each of the last five years of historical data are weather adjusted with coefficients from the Design Day regression model. These weather-adjusted values are then compared to the Design Day forecast. The change in HDDs and wind-speed from the Design Day is multiplied by the HDD coefficient and the wind-speed coefficient from the model and by the historical number of meters to provide the weather adjustment. The throughput and the weather adjustment are summed to arrive at weather-adjust or Design Day equivalent throughput.

The modeled Design Day firm throughput is compared to the Design Day historical equivalent and if the modeled Design Day is less than the historical equivalent, then the historical equivalent value is used. If the modeled Design Day is greater than the historical equivalent, then the modeled Design Day is used.

12. Northern States Power Company, a Wisconsin Corporation[55]

12.1 Summary

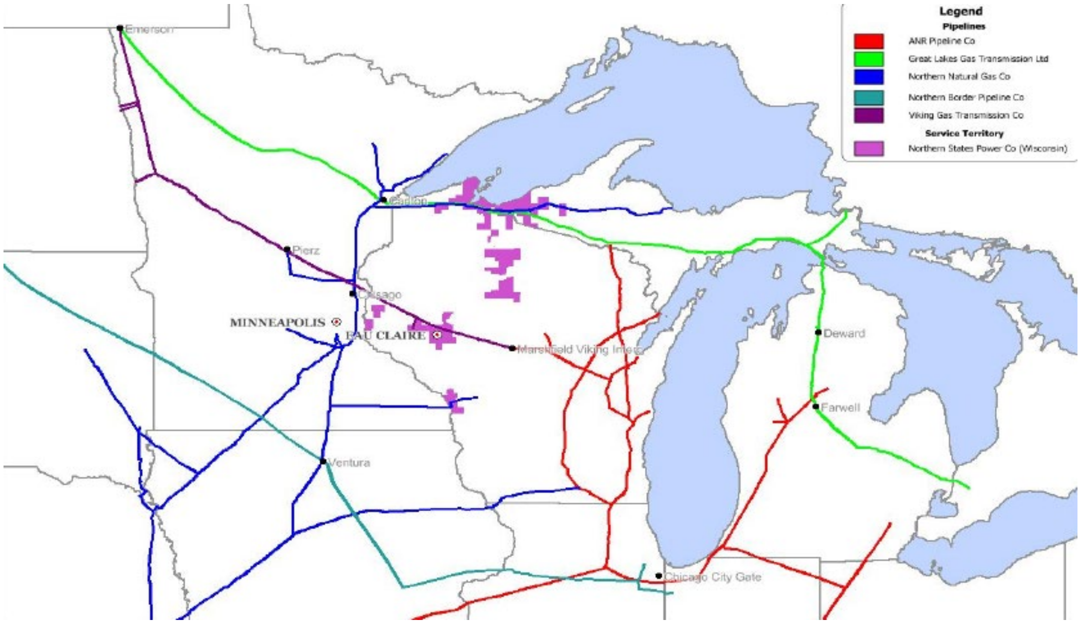
Northern States Power Company, a Wisconsin corporation (NSP-W) operates in both Wisconsin and Michigan. Northern States Power Company has in total approximately 640,000 natural gas customers and delivered 109 million Mcf in 2019. NSP-W uses a set temperature approach to forecast its Design Day requirements.

NSP-W's existing supply portfolio includes several contracts for firm pipeline capacity that allow for multiple pathing options at a reasonable cost. It includes contracts with multiple suppliers with both market-based pricing terms and firm terms. It also has off-system storage with ANR Storage Company (ANR Storage) and Northern Natural Gas Company (Northern) and has a Gas Price Volatility Mitigation Plan. NSP-W uses four interstate pipelines, which are shown in Figure 12-1:

- ANR Pipeline Company (ANR Pipeline),
- Northern,
- Viking Gas Transmission Company (Viking), and
- Great Lakes Gas Transmission Company, Ltd. (Great Lakes).

[55] Northern States Power Company, a Wisconsin corporation Case No. U-20820, Gas Recovery Plan, December 22, 2020.
https://mipsc.force.com/sfc/servlet.shepherd/document/download/069t000000HXJnzAAH?operationContext=S1

Figure 12-1 NSP-W Pipeline Map



In 2020, NSP-W submitted an application for the authority to implement a gas cost recovery plan and establish gas cost recovery factors for the twelve-month period ending March 31, 2022. The following sections outline the approach and methodology NSP-W takes for its Design Day forecast based on its 2020 Gas Recovery Plan.

12.2 Approach

NSP-W forecasts its Design Day requirements through the following approach:

1. Preparing the gas sales budget,
2. Determining the cost of gas,
3. Determining Design Day requirements, and
4. Creating a 5-year forecast of requirements.

NSP-W has used the same methodology to determine Design Day requirements since its filing before the State of Michigan in 2005, Case No. U-14719. Therefore, the following methodology section will reference both Case No. U-20820 and Case No. U-14719[56].

12.3 Methodology

The gas sales budget is determined in two steps:

1. Estimate the number of customers served under each customer class, and

[56] Northern States Power Company, a Wisconsin corporation Case No. U-14719, Gas Recovery Plan, December 28, 2005. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000000wC3mAAE

2. Estimate the monthly sales for all customer rate classes.

Actual historic data and economic and demographic variables are used in standard regression models to estimate the number of customers per month for each of the forecast years for residential and commercial classes. A trend model is used for small customer classes that show little growth. A regression model is also used to determine the monthly sales for larger customer classes. The regression uses historic sales, expected customer growth, weather (i.e., HDDs), and price to drive expected sales growth. For small customers, a linear trend approach was used to estimate monthly sales. To ensure weather-sensitive sales impacts are determined, NSP-W completes an additional calculation that incorporates billing month sales, customers, normal HDDs, monthly coefficients, and the difference between billing month and calendar month days.

NSP-W calculates Design Day customer demand so that it can accurately anticipate the demand at design temperatures and provide firm supply. The approach for calculating Design Day requirements uses actual peak day use per customer data (Actual Peak UPC DD) to project future needs. This method uses recent actual data that is not tempered by data from more moderate seasons, because the Actual Peak UPC DD approach reflects how customers actually reacted on a severely cold day. The Design Day temperature, which is -27 Fahrenheit and 92 HDD, is based on the coldest day on record, which was February 2, 1996. The Design Day calculation does not include consideration for factors such as forecast error, future growth beyond the plan year, loss of supply or anomalous weather; however, NSP-W does contract for deliverable transportation capacity above estimated requirements each winter to ensure it has a system reserve margin in the case of unexpected events.

13. EPCOR Natural Gas Limited Partnership[57][58]

13.1 Summary

EPCOR Natural Gas Limited Partnership (EPCOR) has recently began building its franchise in Ontario, and services customers in the Southern Bruce area. EPCOR filed its Gas Supply Plan for the period of 2019-2024 with the Ontario Energy Board (OEB) in June of 2019. EPCOR also maintains a natural gas distribution service territory in Southern Ontario (i.e., Aylmer), and filed a gas supply plan for this region with the OEB in May of 2019.

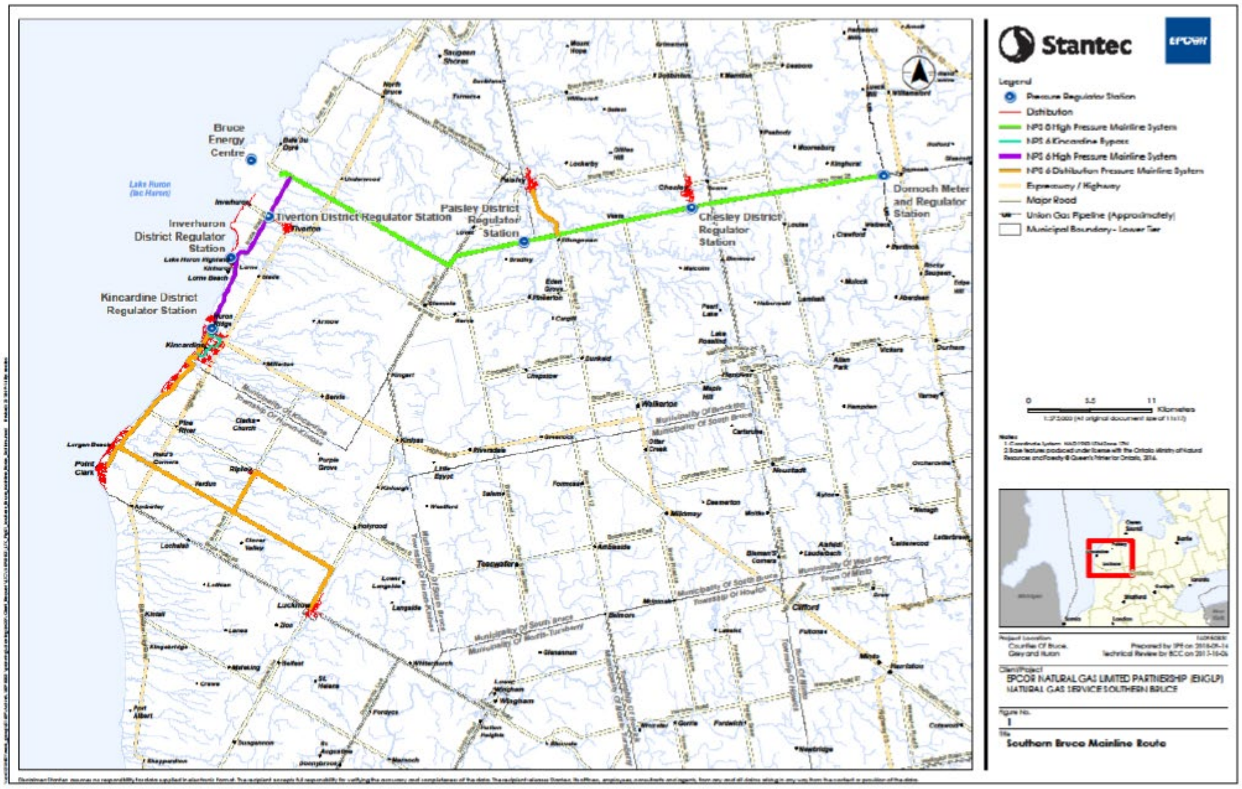
EPCOR requires upstream firm transportation from Dawn and balancing from EGI. At the time of its filing, EPCOR indicated that there was no need for additional upstream firm transportation supply for the Southern Bruce service area. For storage, EPCOR has the same LBA service offered by TCPL to EGI in the TCPL delivery areas WDA, NDA, NCDA, and EDA.

In the Aylmer service area, EPCOR uses Enbridge Gas' system for storage, load balancing and transportation.

A single meter interconnect with EGI at Dornoch services the Southern Bruce Distribution system, which includes the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss. The Southern Bruce Distribution system can be seen in Figure 13-1 below.

[57] EPCOR Southern Bruce Gas Supply Plan: 2020-2023, EB-2020-0106, June 2020. https://www.rds.oeb.ca/CMWebDrawer/Record/679884/File/document
[58] EPCOR Aylmer Gas Supply Plan: 2020-2024, EB-2020-0106, May 2020 https://www.rds.oeb.ca/CMWebDrawer/Record/676153/File/document

Figure 13-1: Southern Bruce Distribution System



EPCOR's Southern Ontario (Aylmer) service territory can be seen in Figure 13-2. This map includes significant infrastructure across the service territory and connections to the legacy Union Gas system.

Figure 13-2. EPCOR Southern Ontario Service Territory

EPCOR services General Service customers, Seasonal customers, and Contract Market customers. The Contract Market customers make up the majority of EPCOR's demand profile by volume (greater than 60% across the two service territories), and they are responsible for their own natural gas supplies and storage assets to manage demand fluctuations. Therefore, the demand profile of these customers is not included in EPCOR's supply plan.

13.2 Approach

To determine its Gas Supply Plan, EPCOR completes the following steps:

1. Calculate customer connection forecast (for the upcoming 3-4 years, using geometric mean annual growth rate for the prior 10 years of actual data)

2. Forecast demand for its expected customer profile through the forecast period

3. Determine Design Day demand requirements.

The following section has more details surrounding EPCOR's Design Day requirements, as disclosed in its Southern Bruce Gas Supply Plan: 2020-2023, and Aylmer Gas Supply Plan 2020 - 2024.

13.3 Methodology

EPCOR does not disclose in its Southern Bruce Gas Supply Plan: 2020-2023 the method it uses to determine its Design Day requirements. It specifies that it has determined peak day demand in Year 10 (2028) and on an annual and seasonal basis it reviews historical average and peak day demand against forecasts made in the Gas Supply Plans. EPCOR also indicated that in February 2023, Design Day requirements would need to be twice the forecasted daily demand volume to exceed the contract demand reserved for its general service customers.

In its Aylmer Gas Supply Plan: 2020-2024, EPCOR indicates that it uses current peak gas demand conditions to predict future peak demands. As part of its peak day/hour analysis, EPCOR is required to develop a peak hour consumption estimate for each of the town centres within its service territory.

After analyzing historical peak demand, EPCOR determined that January 5, 2019 had the highest peak demand, as it was the hour with the largest meter readings. EPCOR applied a 2% year over year growth to this value in its forecast demand requirements based an assessment of historical peak demand growth.

A.1 Full List of Comparators

Table A-1. Full list of Comparators

Jurisdiction	Utility Name	Tier 1 Pass	Tier 2 and Tier 3 Pass	Tier 4 Pass
Illinois	Ameren Illinois Company	Yes	Yes	No
New York	Avangrid (NYSEG and RG&E)	Yes	Yes	Yes
Massachusetts	Boston Gas Company d/b/a National Grid	Yes	Yes	Yes
Minnesota	CenterPoint Energy Minnesota Gas	Yes	Yes	Yes
New York	Consolidated Edison New York Inc	Yes	Yes	Yes
Michigan	DTE Gas Company	Yes	Yes	Yes
Ontario	EPCOR	Yes	Yes	Yes
British Columbia	Fortis BC Energy Inc.	Yes	Yes	No
New York	National Fuel Gas Dist NY	Yes	Yes	Yes
New Jersey	Public Service Electric & Gas Co	Yes	Yes	Yes
Wisconsin	Wisconsin Power and Light	Yes	Yes	Yes
Manitoba	Manitoba Hydro	Yes	Yes	No
New York	National Grid (Downstate NY)	Yes	Yes	Yes
Wisconsin	Northern States Power Co	Yes	Yes	Yes
Utah	Questar Gas Company	Yes	Yes	No
New York	The Brooklyn Union Gas Co	Yes	Yes	No
Michigan	Consumers Energy Company	Yes	Yes	No
Alberta	ATCO	Yes	Yes	No
Colorado	Public Service Company of Colorado	Yes	Yes	No
Iowa, Illinois, Nebraska, and South Dakota	MidAmerican Energy Company	Yes	Yes	No
Arkansas, Colorado, Iowa, Kansas, Montana, Nebraska, South Dakota, and Wyoming	Black Hills Energy	Yes	Yes	No
Illinois	Peoples Gas Light and Coke Company	Yes	Yes	No
Wisconsin	Wisconsin Gas Company	Yes	Yes	No
Pennsylvania and Maryland	UGI Utilities	Yes	Yes	No
Saskatchewan	SaskEnergy	Yes	Yes	No
Alberta	Altagas	Yes	No	N/A
Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee, Texas and Virgina	ATMOS Energy Corporation	Yes	No	N/A
Arkansas, Indiana, Louisiana, Minnesota, Mississippi, Ohio, Oklahoma, Texas	CenterPoint Energy ENTEX	Yes	No	N/A
Maritimes	Emera Energy	Yes	No	N/A
Quebec	Energir	Yes	No	N/A
Maritimes	Heritage Gas	Yes	No	N/A
Southern Idaho	Intermountain Gas Company	Yes	No	N/A
New York, Rhode Island, Massachusetts	Keyspan Energy d/b/a National Grid	Yes	No	N/A
Oregon	Northwest Natural Gas Company	Yes	No	N/A
Washington State	Puget Sound Energy	Yes	No	N/A
Southern Califonia	Southern California Gas Company	No	N/A	N/A
Northern and Central California	Pacific Gas	No	N/A	N/A
Arizona, Nevada, California	Southwest Gas Corporation	No	N/A	N/A
Illinois	Nicor Gas	No	N/A	N/A
Missouri	Spire Missouri Inc	No	N/A	N/A

Jurisdiction	Utility Name	Tier 1 Pass	Tier 2 and Tier 3 Pass	Tier 4 Pass
North Carolina, South Carolina, Tennessee	Piedmont Natural Gas	No	N/A	N/A
Washington D.C	Washington Gas Light Company	No	N/A	N/A
California	San Diego Gas and Electric Company	No	N/A	N/A
Oklahoma	Oklahoma Natural Gas Co	No	N/A	N/A
Indiana	Norther Indiana Public Service Co	No	N/A	N/A
Texas	Texas Gas Service	No	N/A	N/A
Arkansas	CenterPoint Energy ARKLA	No	N/A	N/A
Kansas	Kansas Gas Service Company	No	N/A	N/A
Indiana	Indiana Gas Company Inc	No	N/A	N/A
North Carolina	Public SVC CO of North Carolina	No	N/A	N/A
Maryland	BGE	No	N/A	N/A
New Mexico	New Mexico Gas Company	No	N/A	N/A
New Jersey	New Jersey Natural Gas	No	N/A	N/A
Western Pennsylvania, West Virginia, Kentucky	Peoples Natural Gas Company	No	N/A	N/A
New Jersey	South Jersey Gas Company	No	N/A	N/A
Philadelphia	Philadelphia Gas Works	No	N/A	N/A
Alabama	Alabama Gas Corp	No	N/A	N/A
South Carolina	Dominion Energy South Carolina Inc	No	N/A	N/A
Florida	Peoples Gas Sys	No	N/A	N/A
Greater Philadelphia Region	PECO Energy Company	No	N/A	N/A

A.2 Proposed Approach and the Study Comparators

Following the completion of the jurisdictional review study above, EGI requested that Guidehouse review elements of its proposed approach for determining design day approach and identify to what degree those are consistent with the practices used by the comparator utilities reviewed for this report. In Table A-2. Proposed Approach and the Study Comparators, below, EGI has provided a capsule description of its proposed approach to each of the design day demand modeling elements reviewed by Guidehouse in the jurisdictional review report above (in the column “EGI Proposed Approach”). Guidehouse has reviewed these descriptions and provided a high-level summary of the manner in which the comparator utilities implement the corresponding element to contextualize the EGI-proposed approach.

Table A-2. Proposed Approach and the Study Comparators

Approach Element	EGI Proposed Approach	Approach used by Comparators
	DESIGN WEATHER CRITERIA	
Temperature Selection	EGI is proposing to use the coldest observed temperature over their selected Sample Period (described below).	EGI’s proposed temperature selection for Design Day modeling is consistent with the methodology used by other, comparator utilities. Guidehouse observed that the coldest observed temperature has been recorded in the months of January/February for utilities that utilize a set temperature methodology. As outlined in Table 2-1, most comparators use a set temperature approach. This allows for the use of coldest observed temperature.
Sample Period	EGI is proposing to use a weather data sample with a fixed starting date of November 1, 1979, resulting in an increasing sample period/size over time	EGI’s sample period proposal for Design Day modelling is consistent with the methodology used by other comparator utilities. Guidehouse observed several utilities that utilize a sample period of 40 years or longer.
Wind adjusted HDDs	EGI is proposing to use wind adjusted HDD as part of their approach.	There exists reasonable variation in the HDD parameter used for Design Day modeling by the comparator Utilities. Only two comparator utilities share information on wind adjusted HDDs (also referred as Effective Degree Days, EDDs) used in its Design Day modeling while four others simply provide the design HDD values. Guidehouse observed that the approach proposed by EGI for wind adjusted HDD calculation is consistent with comparator utilities who use this approach.

Approach Element	EGI Proposed Approach	Approach used by Comparators
	PEAK DAY DEMAND MODELLING & FORECASTING	
Peak Day Demand Modelling Approach	EGI is proposing to use linear regression method of the previous winter's actual data extrapolated to design degree day.	Most of the utilities reviewed use statistical analysis (regression-based modeling mentioned in some cases) for estimating the relationship between weather change and gas supply thereby determining the design day standard for maintaining reliability at lowest cost. EGI's proposal to extrapolate previous winter's actual data for Design Day modeling is similar to the approach observed for comparator utilities.

OPERATIONAL CONTINGENCY

STEVE PARDY, MANAGER UNDERGROUND STORAGE & RESERVOIR ENGINEERING

1. The purpose of this evidence is to request OEB approval for operational contingency space and molecule requirements to be included in delivery rates. Impacts on the Gas Supply Plan are discussed at Exhibit 4, Tab 2, Schedule 1.

2. 15.6 PJ of operational contingency will be required to support the reliability and resilience of the Enbridge Gas storage, transmission, and distribution systems. Operational contingency requirements will be managed through injection and withdrawal targets rather than procuring additional storage space. This will result in a 9.5 PJ (current Union rate zone operational contingency) reduction in the in-franchise storage space requirements.

3. This evidence is organized as follows:
    1. Rationale for Operational Contingency
    2. Historical Operational Contingency in Rates
    3. Proposed Operational Contingency and Allocations
    4. Summary

1. Rationale for Operational Contingency

4. As an integrated storage and transmission, and distribution system operator, Enbridge Gas requires operational contingency space to support the storage and transmission services provided to all customers, both in-franchise and ex-franchise. Operational contingency supports the operation of the system by providing the reserve capacity and operational balancing necessary to manage the services provided by Enbridge Gas and ensures the reliability and resilience of the Enbridge

Gas storage, transmission, and distribution systems. Specifically, operational contingency includes empty space at the end of the injection season and filled space (space and molecules) at the end of the withdrawal season to support the operation of the system.

2. Historical Operational Contingency in Rates

5. To manage Union's integrated operations, it was determined in Union's 1999 Rates[1] proceeding that 9.7 PJ would be allocated for operational contingency[2]. As part of Union's Gas Supply Plan, operational contingency requirements were included within its portfolio of cost-based storage in addition to the storage requirements determined by the aggregate excess calculation. As part of Union's 2013 Rebasing proceeding[3], operational contingency for the Union rate zones was revised to 9.5 PJ to include updated data. This was separated between Union North and Union South as shown in Table 1.

Table 1
Union Operational Contingency Requirements

Line No.	Rate Zone (PJ)	1999 OEB-Approved	2013 OEB-Approved
		(a)	(b)
1	Union South	9.1	8.9
2	Union North	0.6	0.6
3	Total	9.7	9.5

6. In addition, the total requirements for operational contingency were determined using various operational parameters as follows: forecasted weather variances, UFG forecast weather variances, system linepack, storage pool hysteresis,

[1] E.B.R.O. 499.
[2] Operational contingency was previously referred to as system integrity by Union.
[3] EB-2011-0210.

OBA/LBA imbalances, and supply backstopping. In Union's 2013 Rates[4], these components were allocated as shown in Table 2.

Table 2
Union Historical Operational Contingency Components

Line No.	Operational Contingency Components (PJ)	2013 OEB-Approved (a)
1	Forecast Weather Variances	2.6
2	UFG Forecast Variances	2.2
3	System Linepack	1.1
4	Storage Pool Hysteresis	2.0
5	OBA/LBA Imbalances	0.9
6	Supply Backstopping	0.7
7	Total	9.5

7. EGD rate zone operational contingency requirements are managed operationally through injection and withdrawal targets rather than procuring incremental storage space for operational contingency purposes. On injection, EGD aimed to leave 4% (4 PJ) empty to manage the system. On withdrawal, the EGD Gas Supply Plan did not plan to fully empty storage as it targeted 43.5 PJ of inventory remaining on February 28 to preserve 1.9 PJ/d of deliverability. Enbridge Gas is forecasting 9.5 PJ of gas to be in storage for the EGD rate zone at the end of Winter 2023/2024. Therefore, Enbridge Gas will have a total of 13.5 PJ of space and molecules available for operational contingency for Winter 2023/2024.

8. The total EGD and Union rate zone space available for operational contingency for Winter 2023/2024 is 23 PJ.

[4] EB-2011-0210.

3. Proposed Operational Contingency and Allocations

9. Enbridge Gas used a model to determine the amount of operational contingency required to support its harmonized storage and transportation services. The model used historical data from the entire Enbridge Gas system to determine the amount of operational contingency required for each of the operational contingency components shown in Table 3. Each component is modeled separately to determine the total operation contingency requirements. The operational contingency model accounts for the fact that events related to the operational contingency will not all occur at the same time, thus reducing the total operational contingency requirement.

10. The total operational contingency requirement was determined to be 15.6 PJ and the proposed allocation of operational contingency components is shown in Table 3.

Table 3
Enbridge Gas Proposed Operational Contingency Components

Line No.	Operational Contingency Components (PJ)	Proposed
		(a)
1	Forecast Weather Variances	7.9
2	System Linepack	1.3
3	Storage Pool Factors	4.8
4	OBA/LBA Imbalances	1.6
5	Total	15.6

11. Each component of the proposed operational contingency is described below. The forecasted weather variance component appears much larger in this proposal as compared to the Union operational contingency from Table 2 due to the relatively larger residential customer base in the EGD rate zone. The EGD rate zone is more than twice as sensitive to weather as the Union South rate zone.

Forecasted Weather Variances

12. Forecasted weather variances account for differences between actual and forecasted weather leading to additional storage requirements that the system operator must manage. To determine the operational contingency space required for injection, variances in weather data for the end of the injection season is used. Weather that is warmer than forecasted will require more space than planned and in particular, a large daily variance requires accessible space for operational contingency purposes. The space and molecules required for the withdrawal season is determined by using weather data throughout the withdrawal season. Daily gas requirements are determined based upon a weather forecast prepared prior to the beginning of the gas day. Weather that is colder than forecasted will require additional gas from storage than planned.

System Linepack

13. Changes in system linepack due to unexpected upsets (in-system, upstream and downstream) and unplanned system demands may result in additional storage requirements to replenish linepack on Enbridge Gas transmission systems and large distribution laterals.

Storage Pool Factors

14. This component was previously called storage pool hysteresis and has been renamed to account for additional factors relating to the operation of the Enbridge Gas storage network. Storage pool factors include: storage pool hysteresis, storage pool deliverability coefficients and storage pool variances.

15. Storage pool deliverability performance can be influenced by localized pressure drawdown across the storage pool as a result of withdrawal and injection

operations. The reduction in the effective pool pressure resulting from this drawdown is referred to as storage pool hysteresis. The lower effective pool pressure results in lower deliverability performance from storage.

16. Total system deliverability is determined based upon a set of storage pool deliverability coefficients for each individual storage pool. These coefficients are known to vary from day to day, season to season and year to year. This variability affects the ability to accurately project the amount of flow into or out of the storage system.

17. Each storage pool in the Enbridge Gas system is shut-in twice annually to allow the pressure within the pool to stabilize. This enables Enbridge Gas to determine the storage pool variances between measured and calculated inventory. However, within the operating season the variance in pool inventory is not fully visible to the operator and can lead to inaccuracies in the available space and molecules available for operations.

OBA Imbalances

18. Operational balancing agreement (OBA) imbalances occur daily at various delivery and receipt points on the Enbridge Gas system with interconnecting pipeline operators. To the extent that OBA imbalances draft the Enbridge Gas system on any given day, an equivalent volume from storage is required to balance supplies and demands on the Enbridge Gas system.

Previous Factors (No Longer Included)

19. UFG forecast variances and supply backstopping components are no longer required to be part of the operational contingency methodology. Existing processes are utilized to manage UFG variances and supply disruptions.

4. Summary

20. The total operational contingency required for the Enbridge Gas storage transmission and distribution systems will be reduced from 23.5 PJ to 15.6 PJ. Additionally, Enbridge Gas plans to adopt the approach of managing operational contingency using cost-based storage inventory targets. The proposed operational contingency space is composed of 4.8 PJ of empty space at the end of the injection season and 10.8 PJ of filled space (space and molecules) at the end of the withdrawal season. The proposed operational contingency space accounts for the fact that the events related to the individual components will not all occur at the same time.

21. 4.8 PJ of empty space is required on November 1 each year to manage late season injection requirements. As storage pools are filled, pools are shut-in for stabilization. This stabilization period is critical to the ongoing inventory monitoring and operation of the storage pools. As pools are shut-in during the latter part of the injection season the number of pools available for injections is reduced. Managing October and November gas receipts becomes increasingly difficult as temperatures can vary considerably at this time of year. The components that are required to manage the 4.8 PJ of empty space include: forecasted weather variances, storage pool factors and OBA imbalances.

22. 10.8 PJ of filled space (space and molecules) is required to meet winter operational requirements resulting from system upsets, imbalances, and forecast variances. The components required to manage the 10.8 PJ of filled space include: forecasted weather variances, system linepack, storage pool factors, and OBA imbalances.

UTILITY STORAGE CAPACITY

MAX HAGERMAN, MANAGER, CAPACITY MANAGEMENT & UTILIZATION

1. The purpose of this evidence is to define the maximum utility firm withdrawal and dehydration capacity of 3.8 PJ/d and the maximum utility firm injection capacity of 1.7 PJ/d associated with the utility storage space of 199.4 PJ available to Enbridge Gas in-franchise customers at cost-based rates. Withdrawal capabilities decrease based on inventory levels[1]; as inventory decreases so does withdrawal capacity. Similarly, as inventory increases, injection capacity decreases. The utility storage space capacity was laid out in the OEB Natural Gas Electricity Interface Review[2] (NGEIR).

2. These storage capacities support the formulation of the Gas Supply Plan, the cost allocation study as well as Enbridge Gas's operational contingency space for the 2024 Test Year Forecast, as provided at Exhibit 4, Tab 2, Schedule 1, Exhibit 7 and Exhibit 4, Tab 2, Schedule 4, respectively.

3. This evidence is organized as follows:
    1. Background
    2. Utility Storage Capacity

1. Background

4. The NGEIR Decision[3] in 2006 established the allocated amount of storage space EGD and Union were required to reserve at cost-based rates for in-franchise customers. EGD was directed to continue to provide its 99.4 PJ of existing storage

[1] EB-2014-0276, Exhibit TCU1.1.
[2] EB-2005-0551.
[3] EB-2005-0551, Decision with Reasons, November 7, 2006.

space for in-franchise customers[4] and Union was directed to reserve 100 PJ of its storage space for in-franchise customers[5]. At the time of NGEIR, Union owned and operated approximately 160 PJ of storage space. The OEB directed that storage space owned by Union in excess of the 100 PJ constituted a non-utility asset for which the shareholders appropriately bear the risk.[6] On a combined basis, the cost-based storage space available to provide service to Enbridge Gas in-franchise customers is the total of the EGD and Union amounts reserved for in-franchise customers of 99.4 PJ and 100 PJ, respectively, or 199.4 PJ in total for Enbridge Gas.

5. EGD did not sell unregulated storage services until some time after the NGEIR Decision. Any injection and withdrawal capacities at Tecumseh at that time were reserved for utility use and have continued to be used to serve in-franchise customers. The maximum utility firm withdrawal capacity from EGD storage operations is 1.9 PJ/d, and the maximum firm utility injection capacity is 0.8 PJ/d.[7]

6. Union sold storage services at the time of the NGEIR Decision that were deemed to be non-utility. Union also had excess deliverability at the time. The costs related to firm deliverability were allocated to regulated and unregulated customers, including the cost related to excess deliverability. To allocate regulated and unregulated costs following NGEIR, Union used cost allocation methodologies consistent with the approved 2007 Cost Allocation Study[8]. This allocation was the basis for a one-time separation of existing storage and general plant assets between the utility and

[4] EB-2005-0551, Decision with Reasons, November 7, 2006, p.11.
[5] Ibid, p.83.
[6] Ibid, p.4.
[7] EB-2017-0086, Exhibit D1, Tab 2, Schedule 9, p.2.
[8] EB-2005-0520, Decisions with Reasons, June 29, 2006.

non-utility businesses. Storage costs related to Union assets that provided deliverability and dehydration capacity were allocated using these methodologies.

7. The OEB affirmed the use of the cost allocation methodologies in the one-time separation of Union plant assets:

> The Board finds that Union has appropriately applied its 2007 Cost Allocation Study for the one-time separation of plant.
>
> The Board notes that the non-utility storage allocation factor utilized by Union is in accordance with the NGEIR Decision. The Board's Decision in NGEIR stated at page 74, "We also conclude that Union's current cost allocation study is adequate for the purposes of separating the regulated and unregulated costs and the revenues for ratemaking purposes."
>
> The Board also notes that the fundamental premise upon which the non-utility storage allocation factor was developed is appropriate. Union's cost allocation methodology was formulated in a manner which reflects how particular systems were designed when they were built and assigns the related costs on that basis.[9]

8. Subsequent to the NGEIR Decision, EGD and Union constructed several storage projects that increased total storage space and firm injection and withdrawal capacity. The cost of these storage projects has been borne strictly by the non-utility business. For projects replacing existing storage assets (no new storage space or deliverability created), the cost of the storage projects have been allocated between the utility and non-utility business based on the cost allocation of the existing asset. This allocation approach is consistent with NGEIR findings where

[9] EB-2011-0038, OEB Decision and Order, January 20, 2012, p.11.

the OEB noted:

> … any new storage which is developed by the utilities will be included as part of the competitive market. The utilities will bear the risk of these investments, not ratepayers.[10]

9. Since NGEIR, the Company has made significant capital investment to increase non-utility withdrawal capacity at Dawn by 1.0 PJ/d and injection capacity of 0.6 PJ/d with all associated costs allocated to the non-utility business. Over the same time period, post 2007, utility demands for firm storage deliverability increased exceeding 2 PJ in February 2019 for the Union rate zones. The Company did not withhold any firm storage deliverability from the utility customers and instead, reduced the maximum firm withdrawals available to serve the non-utility market. The firm withdrawal demands on design day for the Union rate zones are provided at Table 1.

[10] EB-2005-0551, Decision with Reasons, November 7, 2006, p.70.

Table 1
Forecast Firm Design Day Withdrawal Demands – Union Rate Zones

Line No.	Winter (PJ/d)	In-franchise	Excess Utility	Utility	Non-Utility	Total (1)
		(a)	(b)	(c) = (a+b)	(d)	(e) = (c+d)
1	2016/2017	1.8	0.1	1.9	1.5	3.4
2	2017/2018	1.9	0.1	2.0	1.4	3.4
3	2018/2019	2.0	0.1	2.1	1.5	3.6
4	2019/2020	2.0	0.1	2.1	1.5	3.7
5	2020/2021	1.9	0.0	2.0	2.0	3.9
6	2021/2022	2.2	0.0	2.2	1.7	3.9
7	2022/2023	2.1	0.0	2.1	1.8	4.0
8	2023/2024	2.2	0.0	2.2	1.8	4.0

Note:
(1) Over time, total withdrawal demand has increased due to utilization of excess capacity and non-utility capital investments. Non-utility capital investments total 1.0 PJ/d by Winter 2023/2024.

2. Utility Storage Capacity

10. Enbridge Gas has defined the maximum amount of firm withdrawal, dehydration and injection capacity for the storage operations for the Union rate zones as part of this Application. The maximum capacity is set based on the one-time separation of existing storage and general plant assets between the utility and non-utility businesses.[11] As described above, the maximum utility firm withdrawal capacity for the storage operations for the EGD rate zone is 1.9 PJ/d, and the maximum firm utility injection capacity is 0.8 PJ/d.

11. Enbridge Gas has defined the utility maximum firm withdrawal and dehydration capacity as 1.9 PJ/d and firm injection capacity as 0.9 PJ/d for the storage

[11] The one-time separation defined an allocation for existing storage and general plant assets but did not define the maximum firm withdrawal, dehydration and injection capacity associated with those assets.

operations for the Union rate zones. Storage withdrawals require dehydration; therefore, design day dehydration capacity is equal to the withdrawal capacity.

12. To derive the maximum utility firm withdrawal, Enbridge Gas has used the design day capacity for February 28, 2024, and subtracted the capacity associated with the direct investment of non-utility firm injection and withdrawal capacity since the NGEIR Decision. The remaining base capacity is split between the utility and non-utility customers using the same allocation percentages used in the one time split of storage assets, as approved by the OEB.[12] The derivation of the utility withdrawal and injection capacity for the storage operations for the Union rate zones is provided at Table 2.

[12] EB-2011-0038, OEB Decision and Order, January 20, 2012, p.11.

Table 2
Derivation of Total Maximum Utility Capacity – Union Rate Zones

Line No.	Particulars (PJ/d)	Total	Utility	Non-Utility
		(a)	(b)	(c)
	One-Time Separation of Plant			
1	Storage Allocation Factor (1)		62.3%	37.7%
	Withdrawal/Dehydration Capacity			
2	Total Shared Capacity (2)	3.0	1.9	1.1
3	Direct Investment	1.0	-	1.0
4	Total Maximum Withdrawal Capacity (3)	4.0	1.9	2.1
	Injection Capacity			
5	Total Shared Capacity (2)	1.4	0.9	0.5
6	Direct Investment	0.6	-	0.6
7	Total Maximum Injection Capacity	2.0	0.9	1.1

Notes:
(1) Approved storage allocation per EB-2011-0038.
(2) Allocated in proportion to line 1.
(3) Based on design day capacity for February 28, 2024.

13. The utility customers in the Union rate zones have increased their demands for design day storage withdrawals over time and since Winter 2017/2018, utility customers have exceeded the cost-based withdrawal and dehydration allocation of 1.9 PJ/d. The 2024 forecast of utility storage deliverability and dehydration requirements is 2.2 PJ/d which exceeds the reserved cost-based deliverability and dehydration as provided in Table 2.

14. The maximum cost-based deliverability capacity to provide service to Enbridge Gas in-franchise customers is the total of the capacity reserved for in-franchise customers in the EGD and Union rate zones of 1.9 PJ/d and 1.9 PJ/d, respectively,

or 3.8 PJ/d in total for Enbridge Gas. As noted above, the dehydration capacity is assumed to be equal to the withdrawal capacity of 3.8 PJ/d. Maximum injection capacity available is the total of the EGD and Union capacity of 0.8 PJ/d and 0.9 PJ/d, respectively, for a total injection capacity of 1.7 PJ/d available to serve in-franchise customers. The impact associated with utility customers adhering to these maximum injection, withdrawal and dehydration capacities is provided at Exhibit 4, Tab 2, Schedule 1, Section 1.4.

HYDROGEN

SAM MCDERMOTT, TECHNICAL MANAGER RENEWABLE HYDROGEN

1. The purpose of this evidence is to update the OEB on Enbridge Gas's Low-Carbon Energy Project (LCEP) phase 1 and to inform the OEB on the Company's near-term plans related to hydrogen.

2. This evidence is organized as follows:
    1. Hydrogen Blending: Importance and Benefits
    2. Hydrogen Technical Deployment Framework
    3. LCEP Phase 1 Update
    4. Proposed Hydrogen Blending Activities During the Incentive Rate Mechanism Term
    5. Summary

1. Hydrogen Blending: Importance and Benefits

3. The Government of Canada's Vision for 2050, as laid out in Canada's Hydrogen Strategy[1], sets out a national strategic vision which will enable Canada to meet its greenhouse gas (GHG) emissions reduction commitments through the blending of low-carbon hydrogen in the natural gas grid with ambitions to move to 100% dedicated hydrogen through "new dedicated hydrogen pipelines".[2]

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[1] Hydrogen Strategy for Canada, Seizing the Opportunities for Hydrogen, A Call to Action, December 2020. https://www.nrcan.gc.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf
[2] Ibid, p.20.

4. The value of hydrogen is similarly recognized at the provincial level by Ontario's Low-Carbon Hydrogen Strategy.[3] This provincial strategy advocates for blending low-carbon hydrogen into the natural gas grid to reduce GHG emissions in the province. The strategy points to "the important role that hydrogen can play as a low-carbon fuel that can support low-carbon vehicle adoption (e.g., public transportation, forklifts, heavy-duty trucks), decarbonization of space and water heating for homes and businesses and helping industry to decarbonize their processes and meet compliance obligations under Ontario's Emissions Performance Standards Program".[4] The strategy continues that "home heating is one of the largest contributors to a household's GHG emissions. By blending low-carbon hydrogen into the natural gas system, residential customers can reduce their carbon footprint while keeping their existing furnaces, water heaters and other gas appliances."[5] These views on the value of hydrogen are also supported by strategies in other Canadian jurisdictions such as BC[6] and Alberta.[7]

5. Ontario's recognition of the benefits of hydrogen is implicit in its recommended immediate actions in the Ontario Low-Carbon Hydrogen Strategy, one of which is to support what will be the province's largest low-carbon hydrogen production facility, the Niagara Falls Hydrogen Production Pilot.[8] Also noted in Ontario's Hydrogen

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[3] Ontario's Low-Carbon Hydrogen Strategy, A Path Forward, April 7, 2022. https://www.ontario.ca/files/2022-04/energy-ontarios-low-carbon-hydrogen-strategy-en-2022-04-11.pdf
[4] Ontario's Low-Carbon Hydrogen Strategy, A Path Forward, April 7, 2022, p.10. https://www.ontario.ca/files/2022-04/energy-ontarios-low-carbon-hydrogen-strategy-en-2022-04-11.pdf
[5] Ibid, p.29.
[6] British Columbia Hydrogen Study, 2019, https://bcbioenergy.ca/resources/bcbn-publications/british-columbia-hydrogen-study/
[7] Alberta Hydrogen Roadmap, November 2021, https://open.alberta.ca/dataset/d7749512-25dc-43a5-86f1-e8b5aaec7db4/resource/538a7827-9d13-4b06-9d1d-d52b851c8a2a/download/energy-alberta-hydrogen-roadmap-2021.pdf
[8] Ontario's Low-Carbon Hydrogen Strategy A Path Forward, April 7, 2022, p.37. https://www.ontario.ca/files/2022-04/energy-ontarios-low-carbon-hydrogen-strategy-en-2022-04-11.pdf

Strategy is the identification of Halton Hills Energy Centre as a Hydrogen Hub Community, where “Atura Power’s Halton Hills combined cycle gas turbine can be an anchor consumer of low-carbon hydrogen by blending hydrogen with natural gas during periods of peak electricity demand, thereby reducing emissions.”[9]

6. Momentum for hydrogen blending continues to build, highlighting its importance as a tool to help achieve large scale emission reduction targets in a short time frame that is safe, cost effective, and reliable. Since the first phase of Enbridge Gas’s LCEP[10] went into service in October 2021, many other jurisdictions across North America such as Atco Gas and Pipelines Ltd (Atco Gas) in Alberta, Gazifère Inc. (Gazifère) in Québec, FortisBC Energy Inc. (FEI) in British Columbia, Southern California Gas Company and NW Natural in the U.S. have started to pursue hydrogen blending projects or have begun blending hydrogen into their natural gas grids to achieve GHG emission reductions as highlighted below. Enbridge Gas sees the actions of these companies along with actions and commitments from the federal and provincial governments as evidence of growing confidence in hydrogen blending.

7. Atco Gas’s Fort Saskatchewan’s Hydrogen Blending project was announced in July 2020. The project will see blending of 5% hydrogen into the natural gas network for 2000 customers beginning in the fall of 2022.[11]

8. Gazifère and FEI have both expressed their intentions to establish North America’s first carbon free gas grids, using renewable natural gas (RNG) combined with low-

[9] Ibid, p.40.
[10] EB-2019-0294.
[11] Atco Gas. Fort Saskatchewan Hydrogen Blending Project. Fort Saskatchewan Hydrogen Blending. https://gas.atco.com/en-ca/community/projects/fort-saskatchewan-hydrogen-blending-project.html

carbon hydrogen. In Québec, Gazifère has partnered with Evolugen, a division of Brookfield, to build and operate an approximately 20 MW water electrolysis hydrogen production plant in the Outaouais region.[12] The key benefit of the project will be its ability to significantly reduce GHG emissions in the existing Gazifère natural gas grid.

9. According to S&P Global Market Intelligence regarding hydrogen blending across the U.S., "more than two dozen projects announced since 2020 are preparing to get underway, while others are already producing data and yielding lessons for operators"[13], including Dominion Energy Inc. in Utah, CenterPoint Energy Inc. in Minneapolis, NW Natural in Oregon and Chesapeake Utilities Corp in Florida.

10. On June 3, 2022, Minneapolis CenterPoint Energy announced the launch of their green hydrogen blending project which "uses renewable electricity to safely split hydrogen from water, and the zero-carbon hydrogen is then blended at low concentrations with natural gas in the utility's local distribution system."[14] Likewise, on November 10, 2021, New Jersey Resources announced they too have started blending hydrogen into select portions of their natural gas grid "making the gas utility operator the first on the East Coast to blend the zero-carbon fuel into its distribution system."[15]

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[12] Gazifère. (2022). Green Hydrogen in Gatineau, a local project of national interest! https://gazifere.com/en/green-hydrogen-in-gatineau-a-local-project-of-national-interest/
[13] S&P Global. (2022 March 10). Gas utilities get to work piloting hydrogen use in distribution systems. S&P Global Market Intelligence. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-utilities-get-to-work-piloting-hydrogen-use-in-distribution-systems-69302367
[14] Center Point Energy. (2022 June 3). CenterPoint Energy launches green hydrogen project in Minnesota. News Release. https://investors.centerpointenergy.com/news-releases/news-release-details/centerpoint-energy-launches-green-hydrogen-project-minnesota
[15] S&P Global. (2021 November 10). New Jersey Resources starts up 1st East Coast green hydrogen blending project. S&P Global Market Intelligence.

11. Natural gas delivery infrastructure is already in place, and with minimal investment can help the province meet its GHG emissions reduction targets in the short term. This can be achieved with the injection of lower carbon gases into the natural gas grid, while foregoing the need for significant new capital outlay to build net new energy infrastructure, a benefit validated in the Hydrogen Council's Path to Hydrogen Competitiveness report[16], and in the Pathways to Net Zero Emissions for Ontario, as provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 58.

12. Hydrogen blending offers minimal to no interruptions to existing customers, and the cost to implement blending can be spread across millions of customers. This enables a cost-effective achievement of significant emission reductions while maintaining safety and reliability, as well as the provision of continued resiliency to the electrical grid in a very short timeframe.

13. Enbridge Gas sees blending as complementary to both the gas and electric grids, as it enables a deeper intertie between the two. This intertie can enable large scale energy storage utilizing existing infrastructure, enable regulation services to balance the electrical grid, and allow for renewables such as wind and solar to become dispatchable electrical loads. Hydrogen blending also complements the electrical grid as blended gas can be potentially utilized in existing gas power plants and in hydrogen-fired gas-turbines to reduce the carbon footprint of the delivered gas for power generation, benefitting both electric and gas rate payers, as shown in

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https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/new-jersey-resources-starts-up-1st-east-coast-green-hydrogen-blending-project-67570888#:~:text=To%20start%2C%20NJR%20is%20flowing%20a%20less%20than,lawmakers%20in%20Washington%2C%20D.C.%2C%20and%20NJR%27s%20home%20state

[16] Path to Hydrogen Competitiveness: A Cost Perspective, January 20, 2020, p.53, https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

the Pathways to Net Zero Emissions for Ontario report provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 37.

14. The emission reductions that could be achieved with hydrogen blending are material for Ontario. As an example, blending 20% hydrogen into the entire natural gas grid (subject to a full system feasibility study) could yield approximately 2.3 million tonnes of carbon dioxide equivalent (tCO2e) of GHG emissions reduction annually across the system, or the equivalent of removing over 500,000 cars off the road for one year. This illustrates the materiality of GHG reduction potential across the entire province that could be rapidly attained by hydrogen blending.

15. The benefits and costs of hydrogen blending in the natural gas distribution system are recognized and supported by a large share of Enbridge Gas's customers, as evidenced by customer research conducted by the Company in 2019 and 2021. In November 2019, Enbridge Gas undertook customer surveys for phase 1 of the LCEP to raise awareness and to understand the level of acceptance for blending hydrogen in the natural gas grid to lower GHG emissions. The study revealed that "while most customers are not familiar with low-carbon energy initiatives such as blending hydrogen gas with natural gas, the majority of customers support Enbridge Gas making investments in such initiatives (with 76% across the franchise area providing at least some support for such investments)."[17] Approximately half of the Company's customers would support a small increase in their natural gas bill to allow Enbridge Gas to pursue a low-carbon initiative such as the LCEP phase 1.[18]

16. In December 2021, follow-up market research was undertaken as part of a broader customer engagement study as provided at Exhibit 1, Tab 6, Schedule 1, and

[17] EB-2019-0294 (Redacted v2), Exhibit B, Tab 1, Schedule 1, Attachment 6, p.4.
[18] Ibid, p.10.

Attachments. The portion of the research performed to gauge customer support and acceptance for hydrogen blending showed that customer support remains high. When asked about their views on the intent of Enbridge Gas to invest more in the creation of clean hydrogen to allow wider blending in the gas grid, the majority of respondents responded favourably, as provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 257.

17. Enbridge Gas commissioned Guidehouse Canada Ltd. to analyze scenarios that could enable the province to reach net-zero targets by 2050. The Pathways to Net Zero Emissions for Ontario Study, provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, considered two scenarios: (1) a diversified scenario that uses a mix of low-carbon gases, electrification, and technology to achieve net-zero and (2) an electrification scenario focused on using electricity across sectors to achieve net-zero with a minimal role for low-carbon gases. As provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 5, the study revealed that “the electricity and gas systems will become increasingly integrated in the future”, creating an electrical gas intertie, and that “gas-powered generation will play a critical role in Ontario’s electricity systems, and electricity generation will shift from natural gas to hydrogen sources.” The need for hydrogen to meet provincial GHG emissions reduction targets beyond 2030 as described signals an urgency to develop the hydrogen framework to enable carbon reduction through blending. As provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 5, the study reinforced that regardless of which pathway is chosen “Ontario will need a dedicated network of hydrogen pipelines and some gas infrastructure in the province will be repurposed to deliver hydrogen” in blended and pure form.

18. These characteristics of hydrogen – supportive of Ontario’s GHG emission reduction targets, consistent with multiple energy pathways and supportive of

consumer choice and optionality – qualify hydrogen as a clear safe bet focus area for Ontario and Enbridge Gas. Enbridge Gas's definition of safe bet actions is provided at Exhibit 1, Tab 10, Schedule 6, Section 2.

2. Enbridge Gas Hydrogen Technical Deployment Framework

19. To begin blending hydrogen with natural gas on a wider scale across the gas distribution system, a strong statutory and regulatory framework are needed to ensure blending natural gas with hydrogen is appropriately introduced, distributed, and regulated in a manner that provides energy resiliency, safety, and cost effectiveness while lowering GHG emissions in the existing gas grid. Such a framework would drive the development of relevant codes and standards related to distribution assets and end use equipment and ensure that customer rates for hydrogen blended gas are fair and equitable.

20. In the meantime, while these statutory and regulatory frameworks are being developed, Enbridge has already developed its own technical framework to assess the system's hydrogen compatibility and is taking steps to further prepare for system wide blending. The current technical framework is further described below, and additional activities, including a Hydrogen Blending Grid Study (Grid Study), are further described in Section 4.

21. Blending of hydrogen into Enbridge Gas's existing systems currently requires a case-by-case engineering assessment to ensure compatibility with all system components and to establish requisite safety protocols. Enbridge Gas's approach to engineering assessments for hydrogen blending centers on four key elements:
    a) Assessment of existing gas distribution/transmission network;
    b) Assessment of existing end-user network, appliances, and equipment;
    c) Operational readiness and reliability; and

d) Integrity and risk management.

22. The results from each engineering assessment are presented in three categories which reflect an existing system's suitability for hydrogen with minimal, moderate, or substantial capital investment and operational changes.

23. The first category represents segments of the system that are currently compatible with hydrogen with minimal investment of cost and minor operational changes. These could include enhanced leak management practices, recalibration of existing equipment and prioritized repair or proactive replacement of identified assets in order to mitigate the potential for future leaks. Studies indicate that the current distribution system may be suitable for up to 5% hydrogen by volume with relatively minimal changes[19]. Gazifère is currently undertaking a similar study and their results, when available, will be reviewed as further input to and potential validation of this threshold.

24. The second category represents segments of the existing system that could accept the anticipated maximum concentration of hydrogen with moderate capital investment and operational changes. These could include more extensive leak management practices, refurbishment or replacement of leak detection equipment, representative testing of affected customer appliances and equipment, prioritized inspection and testing of select gas piping, and refined risk assessment and integrity management models. While the results of end-use appliance, equipment and materials testing inform their ultimate compatibility with hydrogen, preliminary results from various studies, including the Hydrogen Blending Impact Study from 2022[19], indicate distribution systems may be suitable for up to 20% hydrogen by

[19] Hydrogen Blending Impacts Study, July 18, 2022, pp.106-110. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

volume with moderate replacements, retrofits, and operational changes. Identification of moderate/extensive replacements, retrofits, and operational changes would require an evaluation of Enbridge Gas's natural gas grid as further described in Section 4.

25. The third category represents segments of the existing system for which the anticipated maximum concentration of hydrogen would require substantial replacement or changes. These could include replacement or retuning of most end-user appliances and equipment, as well as means of ensuring system reliability. Once appliances and equipment are tuned to accept a critical threshold concentration of hydrogen, they can no longer operate at lower hydrogen concentrations such that security of hydrogen supply, equipment redundancy, storage and other safety protocols are required. Based on current knowledge, Enbridge Gas's systems may require substantial changes above 20% hydrogen by volume.

26. In some situations, pipeline systems may be requalified to operate with 100% hydrogen. Full conversion to hydrogen will require substantial testing, validation, and upgrades to the system along with enhanced integrity management programs and significant operational changes to ensure continued safety and reliability. Moreover, because hydrogen has lower volumetric energy density compared to natural gas, existing networks will need additional capacity from pipe reinforcement, station replacements or other upgrades to account for the increased volume of hydrogen that will be required to meet energy demand from customers.

27. Enbridge Gas operates an integrated transmission and storage network that interconnects with other natural gas pipelines to serve markets in Ontario, Québec, eastern Canada, the U.S. Midwest and the U.S. Northeast. Agreements will need to

be in place to ensure any changes to gas quality and composition are possible and acceptable to all affected parties. The interconnectedness of the storage and transmission gas system highlights the importance of working closely with affected parties before blending can occur in the system. At this initial stage of blending, focus on local production and injection into an isolated portion of the local distribution system driven by market area consumption is preferred before extending efforts to the storage and transmission systems which serve multiple markets.

28. The large volumes of energy transported through Enbridge Gas's transmission network are currently supported by extensive underground storage systems. Compatibility and geographic availability of potential large-scale media such as aquifers, caverns, or depleted oil wells, will need to be evaluated, and new storage solutions may be required to balance seasonal variability in energy demand in relation to future hydrogen supply and demand.

29. Enbridge Gas continues to advance the industry's understanding and development of hydrogen blending and potential conversion to pure hydrogen by exploring potential initiatives such as:
    a) Research topics focusing on:
        i. Understanding potential for hydrogen leaks in mechanical connections;
        ii. Testing of North American residential and commercial appliances;
        iii. Development of engineering guidelines for hydrogen injection; and
        iv. Studying material and performance compatibility of existing natural gas infrastructure (pipelines, facilities, boiler systems, compressors, etc.).
    b) Standards Development:

   i. Identify required changes to the Canadian Standards Association (CSA) Z662 Oil & Gas pipeline systems standard through the hydrogen and RNG task force; and
   ii. Provide expertise to the Standards Council of Canada's Canadian Hydrogen Strategy Infrastructure Working Groups.

c) Knowledge Sharing:
   i. Engage with companies across the globe to share the latest research, testing, technical developments, and lessons learned; and
   ii. Present hydrogen blending projects at conferences such as Canadian Gas Association (CGA), American Gas Association (AGA) and Western Energy Institute (WEI).

30. As a near-term solution to advance the hydrogen market, Enbridge Gas is a participant in the Canadian hydrogen working groups responsible for hydrogen hubs development in Canada inclusive of Ontario and for the state of readiness for Canada's natural gas networks for the introduction of hydrogen. The groups are led by the Canadian Hydrogen and Fuel Cell Association (CHFCA) and Natural Resources Canada (NRCan) as well as industry associates. This work will complement and support Enbridge Gas's proposed Hydrogen Blending Grid Study.

<u>3. LCEP Phase 1 Update</u>

31. With many more jurisdictions announcing their intent to start, or having just started hydrogen blending projects, Ontario remains a leader in North America with the launch of the first large scale low-carbon hydrogen blending project by Enbridge Gas in Markham, Ontario.

32. The LCEP phase 1 became operational on October 1, 2021 and has been blending low-carbon hydrogen with natural gas for approximately 3,600 customers in the blended gas area (BGA). The operational results to date have been positive.

33. To date, customers in the BGA have logged no complaints related to their blended gas service. As customers enter the second heating season of blending operations, Enbridge Gas will continue to leverage established protocols to respond to any customer feedback, concerns or complaints. The customer response process was put in place in August 2021 and communicated by mail to all customers in the BGA. The process provides customers in the BGA a direct number to call, an email address to log complaints, and call center support with Enbridge Gas's Ombud's Office for issues relating to hydrogen blending. The project website with the project history was also provided to all customers.

34. Hydrogen blending is yielding GHG emissions abatement as predicted. These early positive signs on GHG emission abatement are encouraging for future project performance. To accurately forecast GHG emission reductions from future phases and to ensure the current LCEP phase 1 continues to yield the most accurate results in the most efficient manner, Enbridge Gas plans to undertake continual improvements to address factors that may impact the calculated/projected GHG reductions such as those affecting system downtime, or external interruptions that could indirectly affect the anticipated performance of the blending facility. These actions are meant to better understand and streamline operational costs while improving plant efficiency.

35. An example of a proactive action to lower operating costs while improving system efficiency involves the automating of the plant's ability to switch over from summer

to winter operations and vice versa. This was originally a manual process requiring operational personnel at the start and end of the heating season, and at times when there is a wide fluctuation in temperature swings over an extended period, to ensure switch over is done correctly and systems are functioning as intended. Enbridge Gas has improved this process by enabling the system to automatically switchover from the summer to winter seasons and vice versa negating the need for an operator and lowering the associated operational cost.

36. Finally, the customer billing process has been fully automated to ensure full compliance with the Hydrogen Gas Rider (Rider M) and has resulted in a seamless billing experience for the customer. The amount appears as a credit each month on the bill of customers in the BGA.

4. Proposed Hydrogen Blending Activities During the Incentive Rate Mechanism Term

37. Consistent with Enbridge Gas's Energy Transition Plan and safe bet framework as provided at Exhibit 1, Tab 10, Schedule 6, and to build on the early success of the LCEP phase 1, the Company intends to advance hydrogen blending in the IR term with two key initiatives. The first will be a proposal to develop phase 2 of the LCEP, and the second will be a full evaluation of Enbridge Gas's Ontario natural gas grid's readiness to accept greater amounts of hydrogen to achieve maximum GHG emission reductions. These activities, their benefits, and associated costs are outlined below.

4.1. LCEP Phase 2

38. A multi-phased approach to the LCEP was originally contemplated in Enbridge Gas's LCEP Application.[20] The OEB's Decision in that proceeding specified in its

[20] EB-2019-0294, Exhibit B, Tab 1, Schedule 1, p.10.

conditions of approval that Enbridge Gas would report back with recommendations on next steps, including the potential to expand the project, after 5 years of operational experience in LCEP phase 1.[21] In light of the rapidly evolving energy transition context in Ontario, and based on early successes in LCEP phase 1, Enbridge Gas intends to accelerate the transition to LCEP phase 2. This advancement of hydrogen blending is consistent with the findings of the Pathways to Net Zero Emissions for Ontario which highlight a major role for hydrogen in the diversified scenario as provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 57.

39. LCEP phase 2 is intended to advance low-carbon hydrogen blending to a larger area sooner, validate phase 1 results, understand implications for additional customer classes at a higher blending rate, enable a larger pool of customers for added accuracy and precision of blending, and identify any additional barriers to broader hydrogen blending in Enbridge Gas's Ontario gas grid.

40. It is expected that phase 2 will expand the project to an additional 12,400 customers, bringing the total project to 16,000 customers. In phase 2, a higher blend may be proposed beyond the current 2% in phase 1 of the LCEP. To illustrate the potential for emission reductions, for the additional 12,400 customers, a blend of 5% could yield a GHG emission reduction of approximately 1,138 to 1,343 tCO2e per year, and a blend of 10% could yield a GHG emission reduction of approximately 2,357 to 2,782 tCO2e per year. Costs associated with the implementation of the LCEP phase 2 are estimated at $7 million and are included in Enbridge Gas's Asset Management Plan, provided at Exhibit 2, Tab 6, Schedule 2.

[21] EB-2019-0294, Decision and Order, p.15.

41. Enbridge Gas intends to file a leave to construct (LTC) application with the OEB likely in late 2023 or early 2024, which will contain additional details and project plans for LCEP phase 2.

4.2. Hydrogen Blending Grid Study (Grid Study)

42. Based on the federal and provincial hydrogen strategies and the results of the Pathways to Net Zero study, Enbridge Gas believes that hydrogen blending will have an important role to play in achieving GHG emission reductions in the province. Enbridge Gas is therefore taking steps to prepare for future hydrogen blending within its Ontario natural gas grid. Future hydrogen blending projects will rely on the learnings of the LCEP phases 1 and 2, as well as learnings from work underway at the Company's affiliate, Gazifère. The Gazifère project will see blending undertaken in the entire natural gas grid owned and operated by Gazifère in Québec. It is anticipated that blending may be undertaken potentially at higher blend percentages that would enable Gazifère to meet Québec's provincial legislative requirements.

43. To understand the implications of system-wide blending in Ontario, Enbridge Gas plans to undertake a full evaluation of its natural gas grid in Ontario. The Grid Study will allow Enbridge Gas to evaluate major aspects of its natural gas grid system's readiness to accept higher amounts of hydrogen to achieve maximum GHG emission reductions, building upon the technical assessment framework already in place as provided in Section 2. Achieving hydrogen readiness of the natural gas grid involves identifying and implementing the necessary grid enhancements to enable the grid to accept the maximum tolerable amounts of hydrogen while keeping the grid flowing in a safe manner with little to no impact on the end user. Evaluation of impacts on customer end use appliances and other impacts to

ratepayers will be a component of the study.

44. The scope of the Grid Study will include the establishment of the system's baseline in its current state: understanding where and how much hydrogen can be accommodated, understanding hydrogen tolerance constraints, and understanding how to accept uniform maximum tolerable amounts of hydrogen to achieve the greatest reductions of GHG emissions in a safe and cost-effective manner.

45. The Grid Study is expected to identify the evolution, need and location for dedicated hydrogen pipelines within the province to convey 100% hydrogen to serve customers able to take pure hydrogen while offering flexibility to bypass those unable to accept any amounts of hydrogen. This requires an analysis of revenue considerations, asset utilization (understanding the effects of blending on heat value commitments), selective blending to bypass customers who may not be able to take blended gas or those needing pure hydrogen, establishment of mechanisms to maintain commitments of long-term contractual obligations, and a process to transition to a new hydrogen blended gas market. A 100% hydrogen delivery system would eventually require a system with similar elements to what Enbridge Gas currently has today for the existing natural gas grid inclusive of storage, balancing, transmission, and distribution.

46. Given the urgency to cost-effectively lower GHG emissions in Ontario, Enbridge Gas is looking at avenues to move the Grid Study forward expeditiously. The Pathways to Net Zero Emissions for Ontario Study provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, page 45, highlights that there is a savings potential from /u
a diversified pathway including the deployment of large-scale hydrogen: "The estimated cost for the diversified scenario is $41 billion less as compared to the /u
electrification scenario, cumulative from 2022 to 2050, or 6% lower." /u

Subject to the timing of potential government funding, it is expected that the Grid Study could commence as early as late 2022, with all work slated to be completed by the end of the third quarter of 2026.

47. The findings of the Grid Study will be presented in two stages: an interim and a final report. The interim report will be completed at the midpoint of the project and will provide an update on progress, findings to date, areas covered, and insights into what the study may yield for the period leading up to the final report. It is expected that the interim report may set out an initial minimal recommended amount of hydrogen blend that the system could safely accept. However, this would be subject to change by the time a final report is completed. This two-stage reporting process will enable transparency and keep the OEB, and all other stakeholders informed as the study progresses.

48. A comprehensive final report of the Grid Study is expected around Q3 2026 (subject to starting in late 2022 as planned) and will contain fully costed recommendations for inclusion in a revised Asset Management Plan. In the interim, Enbridge Gas will continue to work with the market to prepare for blending throughout the province.

49. The total cost to undertake this study is estimated at $12 million; this amount is included in the 2023 to 2032 Asset Management Plan provided at Exhibit 2, Tab 6, Schedule 2, Appendix A, page 28. Should this study be eligible for any government program funding, those amounts will be credited against this estimated cost.

5. Summary

50. Hydrogen has an important role to play in reducing GHG emissions from the end-use of natural gas and helping the province and the country meet GHG emission

reduction targets. The fact that hydrogen enables a complementary intertie with the electrical grid for added resiliency means that hydrogen blending benefits both electric and natural gas rate payers. The natural gas infrastructure is present and effective and can deliver near immediate benefits to ratepayers and users of the electrical system as it can absorb excess electrical energy produced, through sources such as wind and solar assets, in the form of hydrogen. This reduces the amount of natural gas needed to be brought into the province and reduces Ontario's GHG emissions.

51. Enbridge Gas's LCEP phase 1 has been blending low-carbon hydrogen with natural gas for approximately 3,600 customers in the study area as predicted. The project is on track to deliver the GHG emissions reductions as forecasted, while maintaining cost and safety on the natural gas grid. It sets the stage for phase 2 of the LCEP, which will be proposed in an upcoming LTC application to the OEB.

52. The cost of phase 2 of the LCEP is currently projected to be $7 million. Enbridge Gas has included this capital cost in its 2023 to 2032 Asset Management Plan.

53. Enbridge Gas seeks to prepare for future hydrogen blending by undertaking a full evaluation of the hydrogen-readiness of its natural gas grid in Ontario. The study will allow Enbridge Gas to evaluate the readiness of all aspects of the natural gas grid to accept greater amounts of hydrogen to enable maximum emission reductions. The cost to undertake this study is estimated at $12 million. The cost may be offset by amounts awarded to Enbridge Gas through government funding programs.

54. These hydrogen-related activities are necessary to ensure that hydrogen can be introduced to the gas distribution system safely and reliably, and at a reasonable

cost to rate payers – without requiring significant changes to end-use infrastructure – a true safe bet action plan. This action further supports Ontario's and Canada's low-carbon hydrogen strategies while enabling GHG emissions reductions as a key element of Enbridge Gas's Energy Transition Plan as provided at Exhibit 1, Tab 10, Schedule 6. Enbridge Gas's customers have been shown to be in favour of initiatives like these, and Enbridge Gas is uniquely positioned with its broad coverage of Ontario to meaningfully advance the role of hydrogen in the province's energy future to achieve large scale GHG reductions in a timely manner.

55. The government of Ontario and the federal government of Canada have both laid out ambitious plans that involve the use of hydrogen to lower GHG emissions on a national and provincial basis. Through hydrogen alone, by 2050 the federal government plans to reduce GHG emissions by as much as 190 MT per year nationally. This includes the use of the existing natural gas grid to blend up to 20% hydrogen and the use of dedicated hydrogen pipelines to deliver low-carbon hydrogen to Canadians. The provincial government also advocated for the need to undertake blending in the natural gas grid citing LCEP phase 1 as a start. Enbridge Gas believes that its plans are fully aligned with both levels of government and is uniquely positioned to deliver on those ambitions.

LOW-CARBON ENERGY IN THE GAS SUPPLY COMMODITY PORTFOLIO

JASON GILLETT, DIRECTOR, GAS SUPPLY
NICOLE BRUNNER, TECHNICAL MANAGER, NEW ENERGY SUPPLY

1. The purpose of this evidence is to request OEB approval to procure low-carbon energy as part of the gas supply commodity portfolio beginning in 2025, and recover the incremental costs associated with this energy through the proposed cost recovery mechanism.

2. Enbridge Gas is proposing low-carbon energy cost recovery through a Low-Carbon Voluntary Program (LCVP) for large volume sales service customers, to be offered on a long-term basis. Any costs not recovered through the LCVP will be included in the recovery of the cost of gas supply commodity purchases for at least the duration of the underpinning commodity contracts.

3. Enbridge Gas will procure up to one percent of its planned gas supply commodity portfolio as low-carbon energy in 2025 and increase these purchases by up to one percentage point per year to up to four percent by 2028. These purchases will likely be made on long-term contracts, five years or greater, and Enbridge Gas is requesting approval of the proposed cost recovery mechanism for the duration of these contracts. Enbridge Gas is not requesting pre-approval of specific long-term contracts for commodity purchases. Instead, Enbridge Gas is requesting approval of a maximum bill impact cap of $2 per target percentage of low-carbon energy per month for the average residential customer, as forecast at the time of procurement, and implied bill impacts for other rate classes as dictated by forecast consumption volumes. This approval would be for at least the duration of the underpinning commodity contracts. This approach allows Enbridge Gas the flexibility to contract

for renewable natural gas (RNG) as part of regular business activities, without creating additional administrative requirements. Enbridge Gas does not plan to use the OEB's Filing Guidelines for the Pre-Approval of Long-term Natural Gas Supply and/or Upstream Transportation Contracts[1], as the procurement of RNG is not directly supporting new natural gas infrastructure and requesting pre-approval of each RNG contract would be administratively burdensome. Enbridge Gas will first offer low-carbon energy to large volume sales service customers on a voluntary basis and will then allocate the remainder of the costs and benefits to the gas supply commodity portfolio purchases.

4. Large volume sales service customers will have the ability to voluntarily assume an elected portion of the pass-through commodity costs associated with low-carbon energy as part of the proposed LCVP. These costs will be recovered through the proposed Rider L effective implementation of this proposal in 2025, as provided at Exhibit 8, Tab 2, Schedule 7, Attachment 2 as part of the harmonized rate handbook.

5. As the gas supply costs associated with this program will not be incurred in 2024, these costs are not reflected in the gas cost calculations provided at Exhibit 4, Tab 2, Schedule 1. The cost of low-carbon energy volumes that are not recovered through the LCVP will be included in the recovery of the cost of gas supply commodity purchases to the proposed forecast maximum of $2 per month per target percentage point as updated at the time of implementation in 2025. As proposed, the maximum bill impact for the average residential customer would be $8 per month by 2028.

[1] EB-2008-0280.

6. The balance of this evidence is organized as follows:
    1. Proposal Overview
    2. Greenhouse Gas (GHG) Emissions Reductions of RNG
    3. Evaluation of Low-Carbon Energy as part of the Gas Supply Commodity Portfolio
    4. Proposed Cost Recovery Mechanism
    5. Summary

<u>1. Proposal Overview</u>

7. With interest for low-carbon energy supported by customer engagement results, provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 293-295 and 382-384, and direct inquiries from large volume customers, Enbridge Gas has evaluated the role that low-carbon energy can have in the gas supply commodity portfolio. As a result, Enbridge Gas is proposing to procure up to one percent of the planned gas supply commodity purchases as low-carbon energy beginning in 2025 and increasing by up to one percentage point annually, up to four percent of the total gas supply commodity portfolio in 2028.

8. Cost recovery of the premium associated with low-carbon energy will first be sought through the LCVP for large volume customers who have opted into the program. Any costs not recovered from voluntary participants for low-carbon energy up to the annual target percent blend will be added into the cost of gas supply commodity purchases. This will provide cost recovery certainty on a long-term basis that is crucial to support the LCVP and provide access to economic low-carbon energy for sales service customers. The maximum quantity that will be streamed through the cost of gas supply commodity purchases is aligned with customer engagement

results and will reduce sales service customers' emissions and their federal carbon charge (FCC).

9. The Company will target an increasing level of low-carbon energy inclusion, moving from up to one percent in 2025 to up to four percent in 2028, capped at a monthly bill impact for each target percentage of low-carbon energy procured. The monthly amount will be based on the forecast gas costs at the time of the low-carbon energy procurement and Enbridge Gas will cap the residential customer bill impact at $2 per month for each target percentage of the portfolio procured as low-carbon energy. This cost will be incremental to the commodity costs currently charged to customers. As the FCC increases by $15 per tonne per year from $80 per tonne in 2024 to $140 per tonne in 2028 [2], the gap between conventional natural gas pricing and low-carbon energy will narrow.

10. Enbridge Gas will procure low-carbon energy through a portfolio of low-carbon energy types that the Greenhouse Gas Pollution Pricing Act (GGPPA), as provided at Exhibit 1, Tab 10, Schedule 3, Section 2, recognizes as being exempt from the FCC. Currently, Enbridge Gas plans to use RNG and the associated definition and reduction recognized by this legislation.[3] If other low-carbon fuels, including hydrogen, become recognized as a means to reduce the FCC applicable to consumption, the Company will consider the inclusion of these low-carbon energy alternatives as part of the low-carbon energy procurement.

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[2] Government of Canada. (2021 August 5). The federal carbon pollution pricing benchmark. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html
[3] Greenhouse Gas Pollution Pricing Act, September 1, 2022, pp.18-19, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf

2. Greenhouse Gas (GHG) Emissions Reductions of RNG

11. Greenhouse gas (GHG) emissions from the combustion of natural gas are avoided when RNG is used, equivalent to 0.05[4] tonnes of CO_2e/GJ for the quantity of supply that makes up the target low-carbon energy procurement. This is the amount of GHG emitted when a GJ of natural gas is burned, whether the source of the GJ is RNG or conventional natural gas. Because RNG (also known as biomethane) is produced from decomposing organic matter (e.g., food waste, human and animal wastes) which is ultimately derived from plants that utilize and remove CO_2 from the atmosphere, the CO_2 emitted from combusting RNG is part of the short-term natural carbon cycle and not a net increase in GHG emissions.[5] The Company will recognize the 0.05 tonnes of CO_2 not emitted by displacing conventional gas with RNG molecules. This is aligned with the reduction recognized in the GGPPA:

> ***Natural gas that contains biomethane***
> ***(7)*** *Unless subsection (8) applies, if a quantity of marketable natural gas or non-marketable natural gas contains a particular proportion of biomethane (expressed as a percentage), for the purpose of this Part, the quantity of marketable natural gas or non-marketable natural gas*

[4] The emission factor for natural gas in Ontario can be calculated from the Ontario Marketable Natural Gas charge of $0.0979/cubic meter (Greenhouse Gas Pollution Pricing Act, September 1, 2022, Table 4, pp.242-245, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf), divided by 2022 carbon price of $50/t CO2 (Government of Canada. (2021 August 5). The federal carbon pollution pricing benchmark. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html) and equals 0.001958 tCO2e/cubic meter.
Using Enbridge Gas's average annual heat content for 2021 of 0.03884 GJ/standard m^3 (Enbridge Gas. Enbridge Gas Inc 2021 Gas Composition and High Heating Value Data. https://www.enbridgegas.com/-/media/Extranet-Pages/About-Enbridge-Gas/learn-about-natural-gas/gas-composition-and-high-heating-value-data.ashx?rev=2d56f5ca107e4b0ba1d031935fb584d9&hash=7FEBBAD0E9AEAF372EFA423F023CDFBA), the emission factor in energy units is 0.05041 tCO2e/GJ.
[5] Report Update: Biomethane Greenhouse Gas Emissions Review, March 31, 2017, https://www.cdn.fortisbc.com/libraries/docs/default-source/services-documents/offsetters-biomethane_greenhouse_gas_emissions_reviewe6fecb594de843768ae02951f4b8d3eb.pdf?sfvrsn=821688c4_2

is deemed to be the number of cubic metres determined by the formula

A × (100% – B)

where

***A** is the number of cubic metres that the marketable natural gas or non-marketable natural gas would occupy at 15°C and 101.325 kPa; and*

***B** is the particular proportion.*[6]

12. The GGPPA allows for the proportion of any RNG contained in the natural gas supply to be subtracted from the total volume reported and subject to the FCC. The FCC is based on the emission factor for marketable natural gas and represents emissions released from the combustion of natural gas and is not based on a lifecycle carbon intensity approach. Biomethane (i.e., RNG) as provided in the GGPPA is described as "a substance that is derived entirely from biological matter available on a renewable or recurring basis and that is primarily methane"[7] and does not take into consideration the various feedstocks or methods of RNG production nor the various carbon intensities that may arise. As a result, replacing one GJ of conventional natural gas with one GJ of RNG regardless of the lifecycle carbon intensity (CI) associated with the supply procured achieves a full reduction in the applicable FCC.

13. On a lifecycle basis, RNG can provide two separate and distinct emission reduction benefits.
    a) Emissions reduced from the production source.

[6] Greenhouse Gas Pollution Pricing Act, September 1, 2022, pp.18-19, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf
[7] Greenhouse Gas Pollution Pricing Act, September 1, 2022, p.5, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf

b) Emissions reduced through displacing combustion of conventional natural gas.

14. As discussed above, since RNG is produced from biogenic sources the CO_2 released to the atmosphere during its combustion is not considered incremental. The capturing of methane that would have otherwise been released to the atmosphere (from the decomposition of organic wastes) is an additional emission reduction benefit that is associated with the production of RNG[8]. Where the avoided methane emissions are eligible to be included in the calculation of RNG lifecycle carbon intensity, the resulting CI is often a negative value. The Company acknowledges the lifecycle emission benefits of using RNG, however at this time, the CI score of RNG will not be the primary consideration when procuring RNG.

15. The CI of RNG procured (and hydrogen when recognized under the GGPPA) becomes an important consideration when it influences the number of credits that may be generated under the Clean Fuel Regulations (CFR). CFR credits created from the production of RNG or hydrogen may be sold to primary suppliers (i.e., obligated parties) where the sale of the CFR credit represents a means of lowering the procurement cost of RNG or hydrogen. Enbridge Gas has no obligation under the CFR (i.e. is not a primary supplier), however it may participate in the CFR on a voluntary basis. CFR credits are new regulatory instruments that were introduced with the publication of the CFR as of July 6, 2022 and can be created by eligible low-carbon fuels that displace natural gas use, as is the case with Enbridge Gas's proposed program. A lower CI score will produce more credits per GJ of RNG or

[8] Clean Fuel Regulations: Specification for Fuel LCA Model CI Calculations, July 2022, p.120, https://data-donnees.ec.gc.ca/data/regulatee/climateoutreach/carbon-intensity-calculations-for-the-clean-fuel-regulations/en/CFR-Specifications-for-Fuel-LCA-Model-CI-Calculations.pdf

hydrogen than a higher CI score, relative to the reference carbon intensity for gaseous fuels as defined in the CFR.[9]

16. The Company has not determined at this time if RNG will be purchased with or without CFR credits. Where Enbridge Gas purchases RNG with CFR credits, it envisions that the benefits, less expenses, generated from CFR credit sales will reduce the incremental cost of low-carbon fuel. Enbridge Gas may elect to procure RNG without CFR credits, where it is forecast that procurement of RNG without the CFR credit leads to more cost-effective procurement. The nascence of the CFR and its credit market means that there is currently credit price uncertainty.

17. As provided at Exhibit 1, Tab 10, Schedule 6, Section 2, RNG, and Enbridge Gas's proposed low-carbon energy procurement is a safe bet, as growing the use of RNG (1) supports near term GHG emission reductions, (2) develops an Ontario-based RNG market that, regardless of the pathway that unfolds, is required to supply RNG to the difficult to decarbonize heavy transportation sector as well as industrial processes, and (3) provides customers with choice on how they can achieve their own GHG emissions reduction goal, while also supporting Ontario in reaching its decarbonization target.

3. Evaluation of Low-Carbon Energy as part of the Gas Supply Commodity Portfolio

18. As discussed in the 2022 Annual Gas Supply Plan Update, the Company determined the need to evaluate the role that low-carbon energy could serve in the gas supply commodity portfolio following supportive customer engagement results specifically for the inclusion of RNG[10]. Through that process, multiple stakeholders

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[9] Canada Gazette Part II, Vol. 156, No. 14, Clean Fuel Regulations, July 6, 2022, Schedule 1, p.2790, https://www.canadagazette.gc.ca/rp-pr/p2/2022/2022-07-06/pdf/g2-15614.pdf
[10] EB-2022-0072, Transcript Day 1, p.91.

showed interest in more information about RNG, with one noting that their members (large commercial customers) are working towards low-carbon operations and net-zero emissions[11]. Stakeholders are seeking more information to be provided via a jurisdictional overview in the rebasing application[12]. As described by VECC, "renewable natural gas has clear benefits to consumers not just in GHG emission reduction but also in potential monetary credits to offset carbon taxes."[13]

19. The Company has undertaken this evaluation, including an assessment of alignment with gas supply guiding principles, lessons learned from the existing Voluntary (VRNG) Pilot Program, through customer engagement and in completing a jurisdictional overview of the low-carbon energy market.

3.1. Alignment with Gas Supply Guiding Principles and Public Policy

20. The OEB's Framework for the Assessment of Distributor Gas Supply Plans (Framework) set out guiding principles for assessment of natural gas distributors' gas supply plans. It identified three guiding principles used in assessing the plans:

- Cost-effectiveness – The gas supply plan will be cost-effective. Cost-effectiveness is achieved by appropriately balancing the principles and in executing the supply plan in an economically efficient manner.
- Reliability and security of supply – The gas supply plan will ensure the reliable and secure supply of gas. Reliability and security of supply is achieved by ensuring gas supply to various receipt points to meet planned peak day and seasonal gas delivery requirements.

[11] Ibid, Comments from BOMA, May 24, 2022.
[12] Ibid, Comments from BOMA, LPMA and VECC, May 24, 2022.
[13] Ibid, Comments from VECC, May 24, 2022, paragraph 8.

- Public policy – The gas supply plan will be developed to ensure that it supports and is aligned with public policy where appropriate.[14]

21. As outlined below, the proposal to procure low carbon energy as part of the gas supply commodity portfolio is aligned with each of these guiding principles.

22. Enbridge Gas's proposal to procure low-carbon energy as part of the gas supply commodity portfolio is a cost-effective means to reduce emissions. Low-carbon energy, specifically RNG, is a market-ready solution to advance progress to make meaningful reductions in GHG emissions while leveraging existing infrastructure and assets in a cost-effective manner that does not compromise reliability of supply. As demonstrated in the Pathways to Net-Zero study for Ontario, provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, under the lower-cost diversified pathway, RNG plays a key role in reducing emissions by meeting 4% per year of gas demands in 2030 and 15% of gas demands by 2050. Enbridge Gas's proposal to allow large volume system gas customers to voluntarily elect to include RNG in their supply allows customers with emissions reductions goals to meet these goals on a long-term basis. RNG that is not elected for as part of the LCVP will be recovered through the gas commodity reference price. This approach maximizes alignment with customers interests in reducing their emissions, while minimizing the marketing costs required to provide that alignment. It also enables Enbridge Gas the critical ability to contract for RNG supply on a long-term basis, allowing for more economic and reliable access to RNG supply.

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[14] EB-2019-0137, Final OEB Staff Report to the Ontario Energy Board - Consultation to Review Natural Gas Supply Plans, March 26, 2020.

23. As provided at Exhibit 1, Tab 10, Schedule 6, government at all levels and customers are focused on reducing GHG emissions and transitioning to a low-carbon economy. Specifically, the Ontario government has committed to reducing emissions by 30% below 2005 levels by 2030, as outlined in the Made-in-Ontario Environment Plan, which is aiming to reduce emissions by 18 Mt of CO_2 by 2030[15]. Enbridge's low-carbon energy proposal is aligned with the spirit of this public policy as it would reduce emissions by over 1.06 Mt of CO_2 by 2028 if four percent of the gas supply commodity portfolio were purchased as RNG. This proposal therefore achieves approximately 6% of the reduction goals in the Made-in-Ontario Environment Plan.

24. Federally, Canada's 2030 Emissions Reduction Plan is requesting a reduction of emissions of 40-45% below 2005 levels by 2030.[16] In March 2022, the Canadian Biogas Association released a report outlining the role that biogas and RNG could play in meeting Canada's Climate Targets[17]. In its findings, the report states that if new policy were introduced to enact a renewable gas blend mandate and create carbon credits for methane destruction and utilization in landfills and agriculture, biogas and RNG within Ontario could contribute an additional 5.6 Mt of CO_2 emissions reductions by 2030, while also reducing methane emissions by 192 kt at the same time[18]. Additional benefits found in this report include creating 19,900

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[15] Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan, November 29, 2018, p.24, https://prod-environmental-registry.s3.amazonaws.com/2018-11/EnvironmentPlan.pdf
[16] Government of Canada. (2022 March 29). Canada's climate plans and targets. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview.html
[17] Hitting Canada's Climate Targets with Biogas & RNG, March 2022, https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf
[18] Hitting Canada's Climate Targets with Biogas & RNG, March 2022, https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf

jobs across Canada and contributing $5 billion in annual GDP. Enbridge Gas's proposal to procure low-carbon energy would contribute to the goals set out in the federal emissions reduction goals.

25. Aligned with the spirit of public policy and cost-effectiveness, and in support of reliable and secure supply, Enbridge Gas is proposing the inclusion of up to four percent low-carbon energy in the gas supply commodity portfolio by 2028.

3.2. Current Inclusion of Low-Carbon Energy in the Gas Supply Commodity Portfolio

26. To date, Enbridge Gas has incorporated low-carbon energy in the gas supply commodity portfolio through the existing VRNG Pilot Program and phase 1 of the Low Carbon Energy Project (LCEP).

27. The existing VRNG Pilot Program was approved[19] and implemented in April 2021. This Pilot Program allows customers to voluntarily pay an additional $2 per month towards the inclusion of RNG in the gas supply portfolio. The VRNG Program was proposed and approved as a pilot to provide an opportunity to begin incorporating RNG into the gas supply commodity portfolio.

28. Enbridge Gas procured 1,000 GJ of RNG in March 2022 based on revenue collected and the forecast of enrolled participants at the time. At the end of Q2 2022, 1,496 customers have enrolled in the VRNG Pilot Program. Enbridge Gas has reduced approximately 49 tonnes of CO_2e through the displacement of conventional natural gas through this transaction. Enbridge Gas will continue to provide enrollment to the VRNG Pilot Program and will offer this program until the approval and implementation of the proposal in this evidence. At that time, the

[19] EB-2020-0066, OEB Decision and Order, September 24, 2020.

Company will use any remaining funds collected from the Pilot Program to procure RNG for the system supply portfolio and discontinue the existing VRNG Pilot Program.

29. The VRNG Pilot Program has allowed Enbridge Gas to procure a small volume of RNG on behalf of program participants; however, the ability to purchase the RNG has been limited by lower-than-expected participation in the program. Enbridge Gas has recognized that participation is strongly correlated with marketing campaign spend and timing, with 77% of enrollments occurring during active marketing campaigns. For example, Enbridge Gas ran a marketing campaign from March 14 to May 31, 2022, during which a monthly average of 208 participants enrolled in the program, compared to a monthly average of only 59 participants in January and February. Enbridge Gas has attempted to maximize the effectiveness of its marketing budget associated with the VRNG Pilot Program, however it would need to significantly increase and sustain the marketing budget to continue to attract additional customers to this program.

30. The target participants of the existing VRNG Pilot Program are residential and small business and commercial customers. Through this program, Enbridge Gas has experienced a cost to acquire of $200 per participant. Assuming the cost to acquire a participant remains consistent, a marketing budget of $4.8 million for the first two years would be needed to achieve participation levels forecast as part of the VRNG Pilot Program. At this level, RNG procurement would continue to fall short of the demonstrated interest for RNG in customer engagement that was expressed.

31. Phase 1 of the existing LCEP program began blending hydrogen into the natural gas distribution system in October of 2021. Through this program, customers have

been able to reduce CO_2e by approximately 57 tonnes between October 2021 and March 2022. Further details of this program are provided at Exhibit 4, Tab 2, Schedule 6. As provided at Exhibit 4, Tab 2, Schedule 6, Enbridge Gas is proposing to undergo a system-wide study to evaluate further inclusion of hydrogen in the system, as well as to come forward with a Leave to Construct application to expand the LCEP into phase 2. Under the GGPPA as of October 2022, hydrogen has not been recognized as a means of lowering the quantity of marketable natural gas that is subject to the FCC, and as such will not currently be considered as part of this low-carbon energy procurement program. Enbridge Gas will continue to blend hydrogen as part of the LCEP to reduce GHG emissions. Should hydrogen become recognized as a means of lowering the quantity of marketable natural gas that is subject to the FCC, and therefore allowing Enbridge Gas to reduce the FCC associated with molecules combusted, Enbridge Gas will evaluate incorporating hydrogen procurement as part of its low-carbon energy procurement.

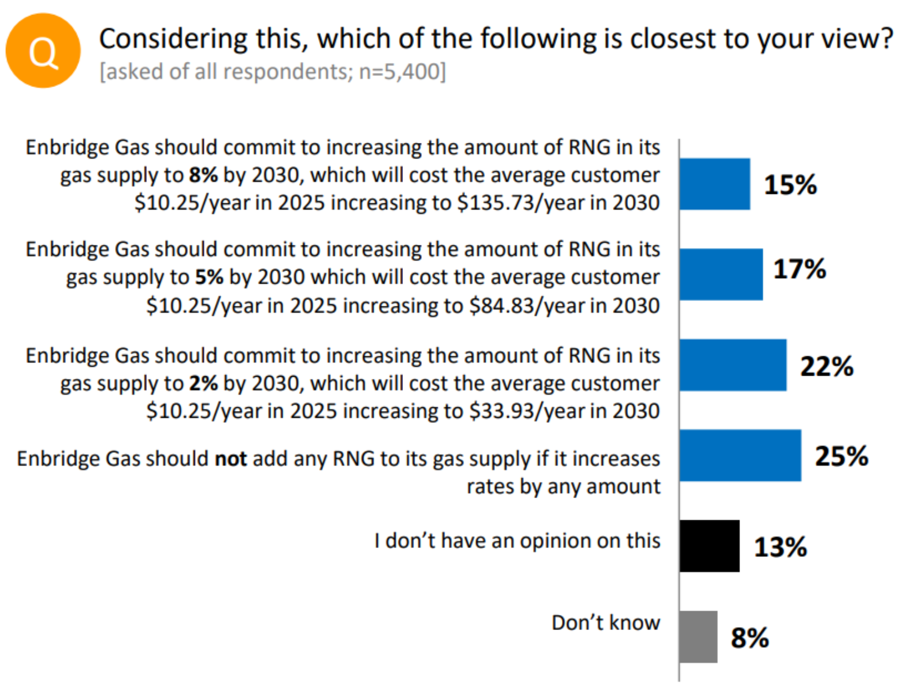
3.3. Customer Support and Engagement

32. As provided at Exhibit 1, Tab 10, Schedule 3, 32% of Ontario's GHG emissions are related to the combustion of natural gas by end-use customers. As noted in Enbridge Gas's customer engagement findings, residential customers ranked "minimizing any impacts on the environment" as a top priority, just behind affordability and the safety and reliability of delivering natural gas as provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 119.

33. Residential and business customers also supported inclusion of RNG in the gas supply portfolio at an incremental cost. Enbridge Gas asked customers to consider including RNG starting at an additional cost to their current rates. As seen in Figure 1 and provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 32, customer

engagement results indicate that 54% of residential customers and 52% of business customers were supportive of incurring these additional costs to support RNG in the system supply portfolio at various levels. As noted above, this support for Enbridge Gas to purchase RNG is not reflected in the low participation rates of the VRNG Pilot Program, likely due to the requirement of residential customers to take positive action to elect their participation. These small volume customers do not interact frequently with the utility, and as a result require considerable Company effort to encourage taking specific actions such as electing to participate in the VRNG Pilot Program. Enbridge Gas's proposal to recover unelected RNG costs through the reference price will allow small sales service customers to benefit from the inclusion of RNG without having to take specific action, which is supported by customer engagement results.

Figure 1: Customer Engagement Results



34. In addition to support for inclusion of RNG in the gas supply portfolio through the customer engagement process, Enbridge Gas is aware of multiple large volume sales service customers who are seeking to lower their emissions using RNG. Enbridge Gas is in the process of assessing this interest and customer requirements. Many of Enbridge Gas's large volume sales service customers have also set goals to reduce emissions and/or become net-zero. Additionally, municipalities and stakeholders have set ambitious goals to reduce their own and their constituents' emissions. Letters of support for the inclusion of RNG are provided at Attachment 1. Enbridge Gas is aware of customers switching to direct purchase (DP) in order to include RNG as part of their gas supply mix, which cannot currently be facilitated through a sales service arrangement. To create opportunities for emissions reductions for both large volume sales service and DP customers, Enbridge Gas is proposing a voluntary program for the inclusion of RNG for large volume sales service customers.

3.4. RNG Market Overview

35. Enbridge Gas engaged Anew Canada ULC. (Anew), formerly Bluesource Canada ULC., to provide a jurisdictional overview of the RNG market in North America and the role of RNG for customers seeking to lower the carbon emissions associated with their supply. This research paper, (Anew Report) is provided at Attachment 2. This report, including the review of other jurisdictions RNG programs such as those in BC and Québec has informed Enbridge Gas's proposal for similar inclusion of RNG in the portfolio on both a voluntary basis and through the gas supply commodity portfolio.

4. Proposed Cost Recovery Mechanism

36. As Enbridge Gas does not have certainty of cost recovery for RNG beyond its existing VRNG Pilot Program, Ontario natural gas customers are at a disadvantage

compared to customers in other jurisdictions as the current VRNG Pilot Program does not support the purchase of RNG with long-term contracts. Enbridge Gas is unable to compete for this supply, as recognized by VECC in the 2022 Annual Gas Supply Plan Update, "As it stands today it would appear that Canada's largest gas distribution utility is unable to compete for renewable natural gas sourced within its own distribution franchise."[20] It is critical for Enbridge Gas to have the regulatory support to meaningfully participate in the RNG market through a cost-recovery mechanism that allows for larger volume and longer-term contracts. Without this support, Ontario customers will be left out of this critical opportunity to lower their emissions.

37. As a result, Enbridge Gas is proposing to discontinue the existing voluntary program for residential and small business and commercial customers upon OEB approval and implementation of the new proposals in this evidence. Enbridge Gas will then remove the $2 per month currently being charged to participants in the VRNG Pilot Program.

38. Enbridge Gas's proposal to begin procuring RNG for delivery as early as 2025, with long-term cost recovery certainty, will ensure Enbridge Gas's customers have an opportunity to access economic RNG supply being produced within the province and potentially across North America. As demand increases on long-term contracts, access to economic RNG supply will becoming increasingly challenging. Enbridge Gas's proposal would enable the Company to enter long-term contracts, subject to the maximum bill impact forecast at the time of procurement, without the administrative burden of requesting individual approval for each contract. This

[20] EB-2022-0072, Comments from VECC, May 24, 2022.

proposal would enable recovery of the cost of gas supply commodity purchases for at least the duration of the underpinning commodity contracts, subject to the maximum bill impact as forecast at the time of procurement.

39. Enbridge Gas will use the existing Gas Supply Plan proceeding, established from the Framework and subsequent Annual Update proceedings, to provide an overview of LCVP results. At the same time, the Company will also report on low-carbon energy procurement activities, including terms of procurement contracts and forecast bill impacts to customers. Enbridge will target four percent of supply by 2028 on long-term contracts, at which point it could consider more low-carbon energy as part of subsequent rebasing applications.

4.1. Voluntary Program for Large Volume Sales Service Customers

40. To provide the ability for large volume sales service customers to reduce their emissions related to natural gas consumption and the cost associated with the FCC, Enbridge Gas has developed a LCVP for large volume sales service customers. DP customers who wish to seek RNG as part of their supply already have the ability to arrange this with their supplier. As a result, Enbridge Gas has developed processes to reduce the FCC on the bill of those DP customers who have attested that their supply is RNG. The proposed LCVP will create a similar ability between sales service and DP customers to reduce their exposure to the FCC.

41. Enbridge Gas is aware of multiple large volume sales service customers who have expressed interest in a more customizable quantity of RNG in their gas supply than is offered through the current VRNG Pilot Program. This customer group interacts more frequently with Enbridge Gas and, with higher consumption, experiences a

greater impact from the FCC.[21] Through existing communication channels with these customers, Enbridge Gas will share the availability of this program without additional marketing spend.

42. With OEB approval, this proposed LCVP will be available for sales service customers in contract rate classes and large volume sales service customers in general service rate classes in 2025, subject to timing of systems enhancements and RNG availability. Prior to the proposed implementation of rate class harmonization, eligible rate classes for the LCVP will be: Rates 6, 100, 110, 115, 135, 145, and 170 in the EGD rate zone, and Rates M2, M4, M5, M7, 10, 20 and 100 in the Union rate zones. Following rate class harmonization, eligible rate classes for the LCVP will be Rate E02, E10, E30 and E34. While some small volume customers in these customer categories may enroll in the program, the program has been designed with a focus on large volume customers.

43. Subject to availability, Enbridge Gas will offer an opportunity for eligible customers to upgrade a portion of their sales service supply to low-carbon energy for a commitment period of one year with renewal in subsequent years. This will allow customers certainty on their emissions reductions on a long-term basis. Participating customers will notionally receive a specified portion of their supply as low-carbon energy and pay the associated premium costs of low-carbon energy above the gas commodity cost. These premiums will vary based on the portfolio of low-carbon energy the Company procures, however this premium will be known at

[21] Facilities that hold an Exemption Certificate issued by the Canada Revenue Agency (i.e., large industrial facilities registered in Ontario's Emissions Performance Standards program) are exempt from the FCC on their natural gas bill. Greenhouse Gas Pollution Pricing Act, September 1, 2022, https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf

the time of the commitment by customers to participate and updated to reflect the average price of low-carbon energy procured by Enbridge Gas.

44. Prior to the time of offering, Enbridge Gas will contract for the low-carbon energy and communicate the average contract price of this supply at the time of offering. Enbridge Gas will pass through the premium for the selected portion of low-carbon energy to these customers over the year of the election.

45. Enbridge Gas will reduce the FCC for these customers on their natural gas bills by an amount equal to the total annual amount of low-carbon energy elected by the customer. Due to timing differences between when the low-carbon energy is delivered into the distribution system and when Enbridge Gas rebates the FCC for that low-carbon energy delivery, variances between actual customer FCCs and actual FCCs collected through rates may arise. These variances will be recorded temporarily in the Customer Carbon Charge – Variance Accounts. On an annual basis, the variance account should net to zero, aligning the remittance of the FCC and the collection with no customer impact. In aggregate, on an annual basis, Enbridge Gas will collect and remit the required FCC from customers.

4.2. *Inclusion of Low-Carbon Energy in Gas Supply Portfolio*

46. As noted earlier, it is critical that Enbridge Gas have the ability to secure meaningful quantities of RNG and other low-carbon energy sources under long-term contracts to ensure that Ontario customers can benefit from economical RNG supply projects. Given current market dynamics, without the ability for Enbridge Gas to commit to larger volumes and longer terms, entities in other jurisdictions will be the first to secure the production and associated benefits at the lower costs. As RNG is typically purchased on long-term contracts, these other jurisdictions will continue to maintain this position in the market for many years. As the FCC

increases and the benefit of RNG grows, Ontario will be excluded from the RNG market, including supply that is produced within the province. To ensure Ontario customers are able to participate in this developing market, Enbridge Gas will seek to secure a portfolio of low-carbon energy under agreements that will be of a large enough volume to procure at a reasonable cost. This will naturally result in a larger portfolio of purchased supply than is elected under the LCVP on a rolling basis. As the pool of RNG is procured, Enbridge Gas will work with large-volume customers to encourage their participation.

47. Low-carbon energy that is not elected in the LCVP will be streamed through the remainder of the planned gas supply portfolio commodity purchases. These purchases include all supply provided by Enbridge Gas. Enbridge Gas will use the gas supply commodity portfolio forecast of planned purchases to determine the quantity of low-carbon energy to procure.

48. As per Exhibit 4, Tab 2, Schedule 1, Table 1, column (b), line 9, planned purchases in the gas supply commodity portfolio for 2024 are 527 PJ. Enbridge Gas will plan to procure up to one percent of the equivalent supply forecast supply requirements as low-carbon energy for 2025 (which includes purchases for system supply, compressor fuel, UFG and own use) and increase target procurement by one percentage point annually until 2028, reaching four percent. Procurement will be executed in alignment with the current gas supply planning principles. Enbridge Gas will seek a diverse, flexible, reliable, and cost-effective supply source of low-carbon energy to meet the target blend percentage.

49. Enbridge Gas will procure this supply to a forecast maximum residential bill impact of $2 per month for each target percentage point of RNG in the system supply portfolio, after reduction of the FCC, at the time of purchase. This maximum bill

impact represents Enbridge Gas's current estimated bill impact for the annual percentage targets assuming no LCVP participation. This approach of establishing a maximum bill impact allows Enbridge Gas the flexibility to procure a diverse portfolio of low-carbon energy, while providing price certainty to ratepayers as market dynamics for low-carbon energy continue to develop. This maximum bill impact will result in rate impacts to additional rate classes that will vary based on their forecast consumption.

50. These costs will be streamed into the cost of gas supply commodity purchases, with variances captured in the Purchase Gas Variance Accounts and remain effective for at least the duration of the under-pinning contracts.

51. As discussed above, Enbridge Gas sought input on the recovery of costs associated with low-carbon energy as part of its customer engagement activities. Customers demonstrated support for inclusion of RNG at an increased cost as a means to reduce their carbon emissions. This support and prioritization demonstrate the need for Enbridge Gas to include RNG in the gas supply commodity portfolio; however, reaching a significant portion of the small general service market on a voluntary basis requires a significant amount of marketing spend. As a result, to align with customers' interest and use funds in the most effective manner, Enbridge Gas is requesting approval for inclusion of the cost premium for low-carbon energy in the gas supply commodity portfolio on a long-term basis.

<u>5. Summary</u>

52. Enbridge Gas has evaluated the role that low-carbon energy can play in the gas supply commodity portfolio and is proposing to include low-carbon energy with cost recovery from the proposed new LCVP and within the reference price. Customers

have demonstrated support for the inclusion of additional costs associated with low-carbon energy, and the benefits of RNG in reducing emissions and FCC are tangibly aligned with public policy.

53. To procure RNG and participate in the market in a meaningful way, Enbridge Gas requires certainty of cost recovery for long-term RNG contracts as soon as possible. Other jurisdictions have recognized an early-mover advantage in procuring RNG in the market and in doing so, have created a more competitive market environment. As the most economic projects are being developed, and in order for Enbridge Gas customers to have access to RNG at a reasonable cost, Enbridge Gas requires the ability to be able to begin procuring RNG on long-term contracts immediately.

54. As a result, Enbridge Gas has proposed the inclusion of low-carbon energy as part of the gas supply commodity portfolio with recovery through two streams starting at up to one percent of gas supply commodity purchases and increasing annually up to four percent of gas supply commodity purchases in 2028. The Company will first offer RNG on a voluntary basis to large volume sales service customers, allowing customers seeking specific quantities of RNG access to this supply as part of their sales service arrangements. Following this, any RNG not voluntarily elected up to the annual blend target is proposed to be streamed through the gas supply commodity portfolio, with costs recovered in the reference price.

55. This cost recovery proposal ensures Enbridge Gas is able to procure RNG by way of long-term contracts, as required to support most RNG projects. This cost recovery certainty will enable Ontario customers to have access to affordable RNG that is currently being sold to other jurisdictions who are recognizing the emissions reductions. Without entering into long-term contracts, Enbridge Gas will lose access

to RNG as demand continues to pull this RNG to buyers with cost-recovery certainty on a long-term basis. As the FCC increases, this will leave minimal options for Enbridge Gas customers to be able to reduce their FCC without incurring higher costs than other jurisdictions.

September 26, 2022

Nicole Brunner
Technical Manager, New Energy Supply
Enbridge Gas Inc.

Dear Ms Brunner:

RE: Support for the proposed Enbridge Gas Low Carbon Voluntary Program

The City of Burlington owns a significant inventory of municipal facilities (ie. administrative, operations and recreational) and, therefore, is a large consumer of natural gas. Burlington City Council has approved a target for city operations to be net carbon neutral by 2040 and community wide by 2050. In 2019, City Council declared a climate emergency.

Renewable Natural Gas (RNG), being carbon neutral, and also exempt from the Carbon Charge, is one way to lower GHG emissions affordably. We understand that Enbridge Gas is looking to evolve its current RNG program to encourage more customers to consume greater quantities of low carbon energy by making it easier to participate.

We understand that the proposed program would offer large volume sales service customers an annual option to voluntarily sign up to receive customizable quantities of RNG and other types of low carbon energy. We support Enbridge Gas procuring RNG via long term contracts to gain access to reliable RNG at the lowest possible cost, given the premium price of short term RNG. This will also have the benefit of supporting RNG developments, jobs, and investments in Ontario.

We further understand that to the extent the large volume sales service customers do not elect to voluntarily sign up, in aggregate, for the full quantities of RNG contracted by Enbridge Gas on a long-term basis, that the excess RNG, including its benefits and incremental costs would be allocated to all sales service customers.

These complimentary inclusions of RNG in the Enbridge Gas gas supply portfolio allow large sales service customers to easily obtain the RNG quantities they desire to help meet their GHG reductions goals at more affordable prices. At the same time, all system sales service customers will also have access to RNG.

We are interested in how this program can help us reduce our emissions and achieve our reduction targets noted above. Climate change is a global issue with significant local impacts, as we are seeing warmer, wetter and wilder weather in our community.

We support Enbridge Gas' efforts to invest in and expand the RNG program to assist the City in its efforts to reduce its carbon footprint.

Sincerely,

Allan Magi, P.Eng.,
Executive Director, Environment, Infrastructure and
Community Services

cc: Lynn Robichaud, Manager of Environmental Sustainability
City of Burlington

London
CANADA

300 Dufferin Avenue
P.O. Box 5035
London, ON
N6A 4L9

September 26, 2022

Nicole Brunner
Technical Manager, New Energy Supply
Enbridge Gas Inc.
Via: Nicole.Brunner@enbridge.com

Re: Municipal Support Letter – Proposed Enbridge Gas Low Carbon Voluntary Program

On behalf of the Corporation of the City of London, we are pleased to express support for Enbridge Gas' proposal for their Low Carbon Voluntary Program. The proposal is consistent with the directions of Municipal Council with respect to actions to address climate change as per London's Climate Emergency Action Plan.

We understand that Enbridge Gas is looking to evolve its current renewable natural gas (RNG) program to encourage more customers to consume greater quantities of low carbon energy by making it easier to participate. Specifically, the proposed program would offer large volume customers the option to voluntarily sign up to receive specific quantities of RNG and other types of low carbon energy (e.g., hydrogen), with surplus RNG being allocated to the system gas used by smaller volume customers.

The City of London is committed to learn more and will consider this action as we move forward with implementation of our compressed natural gas fueled waste collection vehicles as well as explore options for landfill gas utilization.

Thank you for the opportunity to participate in this important project proposal. Please do not hesitate to contact Jay Stanford if you require further details (519-661-2489, ext. 5411 or jstanfor@london.ca).

Sincerely,

Kelly Scherr, P.Eng., M.B.A., F.E.C.
Deputy City Manager
Environment & Infrastructure

Jay Stanford, M.A., M.P.A.
Director, Climate Change, Environment &
Waste Management

Tibbar Services Inc.
690 Fountain St N
Cambridge, ON, NH3 4R7

Attention: Nicole Brunner, Technical Manager **September 30th, 2022**
New Energy Supply

RE: Support for the proposed Enbridge gas <u>Low Carbon Voluntary Program</u>

Tibbar Services Inc (TSI) is 'for hire' truck fleet located in Cambridge Ontario was established in 2013. As a fleet owner and a master diesel mechanic I have adopted natural gas technology because of the lower cost of fuel and the simpler maintenance schedule of CNG trucks help me run a profitable enterprise. Natural gas has been a good hedge in a volatile diesel market.

TSI now owns and operates seven CNG branded trucks. Our company logo celebrates the connection to natural gas with a rabbit that "emits" methane as a visual cue to prospective customers. The intent of the TSI logo is to drive communication about the favourable environmental aspects of transportation with natural gas.

A greater availability of Renewable Natural Gas (RNG) would position my company and other like minded CNG fleet owners to respond for demand from shippers who wish to demonstrate lower emissions through their inbound and outbound supply chains.

Therefore, I support a voluntary program for Renewable Natural Gas for these reasons:

- Brand Alignment – TSI is positioned as a provider of transportation services with a lower impact on the environment. Easy access to RNG gives empowers my company to differentiate from mass market carriers,

- CNG Stations – presently my suppliers of CNG include Hiller Truck Tech (HTT) and Clean Energy (CE). They have indicated that procuring RNG is administratively challenging, and,

- NRCan Green Freight Program – HTT, CE and others have indicated that incentives for natural gas trucks will be contingent on the running the trucks on some amount of RNG. Any policies that promote the availability of RNG will help TSI and other CNG fleets to successfully participate in Federal market transformation programs.

Sincerely,

B. Wigle
President and Owner, Tibbar Services Inc.
Cell 519.505.7963
brian.tibbar@yahoo.com

RURAL GREEN ENERGY INC.

440 Wright Boulevard, Unit #2,
Stratford, ON, N4Z 1H3
519-625-8025
Email: info@ruralgreenenergy.ca

September 28th, 2022

To: Enbridge Gas Inc.

Attention: Nicole Brunner, Technical Manger
New Energy Supply

RE: Support for the proposed Enbridge gas Low Carbon Voluntary Program

Our company located in Oxford County Ontario was established in 2015 with the objective of delivering RNG fuel produced on rural Ontario farms to the transportation industry. At the time we realized that no market existed in the province which encouraged a financial incentive for fleet owners to adopt gas engine technology in lieu of traditional diesel engines. We had to rely solely on savings in fuel costs of CNG vs diesel to persuade fleets to adopt. Although adoption in the USA continued to progress, particularly in California, where government incentivized pricing remained an encouragement for low carbon fuel sources displacing diesel as the preferred transportation fuel. Over the past seven years many engine innovations have encouraged this trend and disastrous weather events globally have reinforced the need to decarbonize our current fossil energy supply source.

We believe that renewable natural gas offers governments and industry a better opportunity short term (next 15-20 years) to reduce our global dependency on traditional fossil derived gas. It resolves our societal need to recycle & reuse waste products in an increasingly circular economy while diminishing carbon emissions. It can be accomplished using existing pipeline & fuelling infrastructure for distribution that is far reaching for both fuelling heavy duty trucks and serving pipeline located industrial, commercial & home users. The same infrastructure, within limits, can play a role in the gathering of rural production gas and making it available to all these remote consumers as well.

Currently, we contract our rural production RNG gas to Fortis B.C. an out of province utility offering us an opportunity to develop Ontario based rural farm renewable gas production sites under long term fixed contracts. This is needed to permit our investor supported project activity & continued growth of rural gas production sites throughout the province. It would be advantageous to us to engage in similar future contracts with Enbridge such that the carbon credits remain within Ontario assisting the province to achieve its greenhouse gas mitigation commitments.
In addition our supplied RNG into the Enbridge gas portfolio give them the RNG quantities needed to be able to provide both small volume and/or large volume users to voluntarily participate towards achieving GHG reduction goals/targets.

In conclusion this proposed RNG program offering by Enbridge would impact us positively as our success is dependent upon increased number of production sites of RNG throughout rural Ontario and encouragement towards adoption of transportation fleets to consider alternate low carbon fuels.

K. Wayne Blenkhorn, P. Eng., CEO
CNG/RNG Rural Green Energy Inc
Cell 519-404-7866
wayne@ruralgreenenergy.ca

October 6, 2022

Attention:
Nicole Brunner
Technical Manager, New Energy Supply
Enbridge Gas Inc.
Via: Nicole.Brunner@enbridge.com

Subject: Support for the proposed Enbridge Gas Low Carbon Voluntary Program

Canada Bread Company, Limited (doing business as Bimbo Canada) hereby states:

Grupo Bimbo is the world's largest baking company, whose purpose is to build a sustainable, highly productive, and deeply humane company. The company operates in 32 countries throughout the Americas, Europe, Asia and Africa, and encompasses many familiar brands, including Oroweat, Bimbo, Tia Rosa, Sara Lee and more. Bimbo Canada is a subsidiary of Grupo Bimbo.

Grupo Bimbo announced in November 2021 its commitment to achieve Net Zero Carbon emissions by 2050. This commitment considers emissions for its entire value chain, covering all Scopes across all activities. By doing this, Grupo Bimbo has become the first Mexican food company to commit to Business Ambition for 1.5°C and join the United Nation's Race to Zero Campaign with targets established and validated by Science Based Targets. More urgently, Grupo Bimbo has committed to a 50% reduction in Scope 1 emissions by 2030.

Renewable Natural Gas (RNG) is one way to lower GHG emissions affordably. We understand that Enbridge Gas is looking to evolve its current RNG program to encourage more customers to consume greater quantities of low carbon energy by making it easier to participate.

Bimbo Canada shares the belief that an innovative project to promote the use of RNG should be developed in Ontario to derive economic and environmental benefits of a low-emission energy vector and which Bimbo Canada could participate in as a consumer in the future.

Sincerely,

Canada Bread Company, Limited

DocuSigned by:
a Lee
9B2774715A034DD...

By: ______________________________
Name: Alice Lee
Title: VP Legal

06 October 2022 | 10:04:56 AM CDT

HILLER TRUCK TECH Inc.

Saving Fuel and the Environment

Attention: Nicole Brunner, Technical Manager **October 3rd, 2022**
New Energy Supply

RE: Support for the proposed Enbridge gas Low Carbon Voluntary Program

Hiller Truck Tech Inc (HTT) is truck repair and CNG fitment facility located near Cambridge Ontario was established in 2004. As a diesel mechanic I have introduced natural gas technology to my customers because of favourable environmental impact of these trucks relative to Diesel Trucks.

The consistently lower cost of fuel and maintenance is attractive to HTT's customer fleets. To support our customers HTT now owns and maintains a fleet of over twenty Class 8 CNG trucks under a rent-to-own program with Enbridge. These trucks travel from the Windsor Ontario in SW Ontario, through to Ottawa in Eastern Ontario, North to Sudbury, and South to Fort Erie. HTT owns a CNG station to facilitate fuel access. Increasingly, my customer fleet are asking about access to Renewable Natural Gas (RNG) from the HTT and other stations. My early research has shown that commercial access to RNG is anything but easy in Ontario.

A greater availability of Renewable Natural Gas (RNG) would enable HTT and HTT's associated CNG fleet clients to respond for demand from corporate customers shippers who seek to lower their GHG emissions.

As such, strongly supports a voluntary program for Renewable Natural Gas.

Best Regards,

David Hiller
President, Hiller Truck Tech Inc.
Cell (519) 635-3675
david@hillertrucktech.com

Enbridge Gas Inc.

North American Renewable Natural Gas Market Evaluation

September 2022

Prepared by:

anew

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Salt Lake City | San Francisco | Calgary | Toronto | Washington DC

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Conditions of Use

This overview titled "North American Renewable Natural Gas Market Evaluation" was prepared for Enbridge Gas Inc. (including any documents attached hereto or incorporated herein). This analysis represents Anew's good-faith effort to provide an objective and accurate summary of current and anticipated future market conditions, based on Anew's long-standing and extensive experience in such markets and third-party observations and data. Market conditions can change, however, at any time, and may (and likely will) be affected by multiple factors outside of Anew's control. Anew expressly disclaims any obligation to update this analysis.

Anew believes that all information in this market analysis is accurate. However, Anew has, in some cases, relied on information obtained from third parties in preparing this analysis and makes no warranty as to the completeness or accuracy of information obtained from such third parties, nor can it accept responsibility for errors of such third parties, appearing in this analysis.

Executive Summary:

Enbridge Gas Inc (Enbridge Gas) is the largest regulated local distribution company (LDC) in North America by volume. Enbridge Gas engaged Blue Source Canada ULC (now Anew Canada ULC, "Anew") to evaluate the role of green gas for customers seeking to decarbonize their gas supply and to provide a jurisdictional overview of the renewable natural gas (RNG) market in North America. Anew focused on analyzing RNG availability and current voluntary or mandated compliance programs in North America jurisdictions.

Anew Advisory defines RNG as being derived from biomass or other renewable resources and is a pipeline-quality gas that is fully interchangeable with conventional natural gas.

Given the above, our key findings include:

- **Supply:** North America RNG production has grown substantially over the last decade and should continue to expand given forecasts of ample (nearly 44,000) project site inventories, feedstock potentials, and investment interest.[1] Each producing project has unique capital investment requirements, costs for processing and operations, RNG yields, and resultant lifecycle carbon intensity (CI). As more fully cited later in the body of this report, forecasters expect that North American RNG supply, led by carbon negative RNG, could substantially decarbonize gas consumption. Based on current project site inventories as noted above and the average reference output volumes developed by independent analysts (as developed later in this document, Table 5.1.1), the RNG produced across the inventory of U.S. project sites could decarbonize as much as 48% of current North American natural gas demand. Other potential projects involve the thermal gasification of woody residue and other waste biologic feedstocks. These technologies are being demonstrated for feedstocks that are difficult for anaerobic digestors to process. Other potential projects may come about by utilizing power to produce gas via electrolysis and methanization. These technologies, although considered pre-commercial today, will develop over time with support and bring more RNG supply into the market.
- **Demand:** The primary drivers of North American RNG demand are U.S. Federal and California state compliance programs mandating roadway fuel decarbonization. North American transportation market demand for RNG in 2025 could absorb nearly 370,000 dekatherms (Dth) per day according to the latest estimates by the RNG Coalition.[2] RNG is also in demand for renewable power generation, building and process heat. Other jurisdictions, including Canada, are instituting green programs in the transportation and gas utility sector. Corporate and household voluntary efforts are also increasing North American RNG demand. RNG's ability to be flexibly used across the continent for fuel or feed stock with low or negative CI drives the demand. Some forecasters expect RNG to fully supplant geologic gas use as economical RNG supplies expand and as efficiency and electrification limit gas demand growth overall.
- **Market Pricing and Structure:** The highest price for North American pipeline-delivered RNG is typically set by "stacked" or summed values for RNG. In Canada, stacked values for RNG can be realized by recognizing the avoided tax under the federal Greenhouse Gas Pollution Prevention Act and other potential value-adding programs like the B.C. Low Carbon Fuel Standard (LCFS). The

[1] RNG Coalition SMART Initiative Plan to Utilize Methane Capture — The Coalition For Renewable Natural Gas

[2] Provided by RNG Coalition, from within their commissioned study, "Renewable Natural Gas: Transportation Demand Supplemental Estimates", April 29, 2022, by Bates & White Economic Consultants, as restated by conversion factor of 1 ethanol gallon equivalent to 0.0853 Dekatherms.

highest values that RNG can achieve today come from stacking the California's LCFS and the U.S. Federal Renewable Fuels Standard program. Not all RNG production qualifies for stacked pricing, and RNG prices also vary with rarity, production costs, market accessibility, and decarbonization potency. Negative CI RNG commands the highest prices and therefore remains attractive to produce despite generally higher operating and capital costs. Broad market access is enabled by extensive North American pipeline infrastructure. That, along with book and claim mechanics assure that stacked prices typically hold, except for small tariff basis deductions, for continental buyers and sellers of similar quality RNG. RNG can be procured by voluntary and compliance buyers via direct or intermediated counterparty transactions or on the transparent M-RETs exchange that allows digital trading of RNG one dekatherm at a time.

- **Jurisdictional Program Reviews:** Several major natural gas utilities in North America have implemented 'green' tariff programs for residential and commercial customers. These programs are a mix of mandatory and voluntary to participants and are offered on a cost recovery basis with set prices per block to offset natural gas and/or greenhouse gas emissions. Some programs offer a combination of RNG and carbon offsets (5% and 95% respectively) to achieve emission reductions. Marketing costs can be a large percentage of the program costs for these voluntary programs, potentially reducing the spend that could have been used to achieve further RNG procurement. Some of the mandatory programs have been successful based on their ability to secure long term contracts with suppliers at prices lower than the spot market.

1.0 Introduction

Enbridge Gas Inc. (Enbridge Gas) is in the process of submitting an application for rate rebasing with the Ontario Energy Board (OEB). As part of this application Enbridge Gas is proposing to evolve their current Voluntary RNG (VRNG) pilot program. As a result, Enbridge Gas seeks to better understand the challenges and opportunities of RNG as well as the approach that utilities in other jurisdictions have taken, to inform their proposed RNG program to the OEB.

Bluesource Canada, ULC[3] (now Anew Canada, ULC. [Anew]) was retained by Enbridge Gas to perform a jurisdictional overview of the RNG market in North America and identify and discuss how other large-scale utilities use green energy products. The scope of work included the following:

- a jurisdictional overview of the renewable natural gas market in North America;
- a scan of North American utilities who currently use green energy products as part of their gas supply portfolio to reduce the emissions of their customers on a voluntary and non-voluntary basis;

The following research report addresses the above scope of work for North American RNG markets.

1.1 Background

In the November 2018 Made-in-Ontario Environment Plan, the Ontario Government indicated its plans to meet Ontario's 2030 emission reduction target, including increased use of clean fuels such as RNG. The Government also highlighted its goal of increasing access to clean and affordable energy for families. Taking these items into account, the Made-in-Ontario Environment Plan[4] required natural gas utilities to implement a voluntary RNG option for customers.[5]

In 2021, the OEB approved Enbridge Gas's application[6] to implement a voluntary pilot RNG program that provides interested customers with the opportunity to pay a $2 monthly charge enabling Enbridge Gas to purchase RNG as part of the company's overall gas supply. The amount of RNG procured depends on the number of participants in the program, the availability of RNG, as well as the cost difference between RNG and conventional natural gas. The incremental cost of RNG above the cost of conventional natural gas supply is funded entirely by program participants, with no direct costs for RNG procured assigned to non-participants.

The biggest challenge of the current program is the limited volume of RNG that Enbridge Gas can procure based on program participation that restricts Enbridge Gas from securing long-term contracts at lower rates. This inability to secure long-term contracts does not future proof the program or allow for scalability should a renewable fuel mandate be implemented in the future requiring utilities to incorporate a set goal of RNG into their supply. As determined by the OEB during the previous application, Enbridge Gas cannot

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[3] Bluesource ULC was contracted by Enbridge Gas Inc. in May, 2022. As of July 4, 2022, Blue Source Canada, ULC (**Bluesource**) merged with Element Markets, LLC (**Element**), another developer of carbon and environmental credits, to form a combined entity now called Anew Climate, LLC ("**Anew**"), which is under majority ownership by TPG Rise and TPG Rise Climate, global impact investing platforms managed by alternative asset firm TPG. Anew Canada, ULC is a Canadian subsidiary of Anew Climate, LLC.

[4]Government of Ontario, 2018. Preserving and Protecting our Environment for Future Generations: A Made in Ontario Environment Plan. Ministry of the Environment, Conservation and Parks. 2018. See page 33. https://www.ontario.ca/page/made-in-ontario-environment-plan

[5] Direct Purchase customers have the option to procure RNG. Enbridge Gas introduced the 2021 voluntary program to enable RNG access for system supplied customers.

[6] Ontario Energy Board, 2020. Decision on Order on Cost Awards, EB-2020-0066: Voluntary Renewable Gas Program Application. October 29, 2020. https://www.rds.oeb.ca/CMWebDrawer/Record?q=casenumber:EB-2020-0066&sortBy=recRegisteredOn-&pageSize=400#form1

have non-participating customers bear any costs of the program. Therefore, current procurement of RNG is in the secondary market once sufficient revenue has been collected from the participants to secure a tranche of supply.

Enbridge Gas is evaluating the role of RNG in its portfolio and is seeking a scalable program that aligns with customer interest in RNG while working towards lowering its greenhouse gas (GHG) footprint. Enbridge Gas completed customer engagement, filed in the Annual Gas Supply Update, that demonstrated both general service residential and business customers are supportive of paying a premium for RNG as part of their gas supply.[7]

2.0 Regulations Supporting RNG Development

A number of federal, provincial, and state policies, regulations, and programs have had a significant role in shaping the current RNG market in Canada and the U.S. RNG is sensitive to government policy because traditionally, climate solutions have not had an intrinsic market value[8]. This means that RNG has been less cost competitive against its traditional fossil-fuel equivalents because its significant climate advantage and benefits have not been reflected in the price. Government policies at the federal, provincial and state levels are helping to correct this market failure. Policy incentives along with more project development and potential technological improvement will likely shrink the prevailing but likely durable price premium of RNG relative to conventional natural gas. A summary of these initiatives is provided below.

2.1 Canada

Greenhouse Gas Pollution Pricing Act

The Greenhouse Gas Pollution Pricing Act[9] (GGPPA) is a Canadian federal law establishing a set of minimum national standards for carbon pricing in Canada to meet emission reduction targets under the Paris Agreement. The aim of the legislation is to put a price on all greenhouse gases through binding "minimum national standards" on the federal government and all of the provinces and territories. The standards on pricing are divided into two parts: Part 1 is a regulatory charge on carbon-based fuels[10] and Part 2 is an output-based emissions trading system for polluting industries[11] (Output Based Pricing System [OBPS]).

Part 1 of GGPPA establishes a fuel charge, which is a regulatory charge on fossil fuels. It is generally paid by fuel producers and fuel distributors in backstop jurisdictions.[12] The fuel charge applies to 21 fossil fuels including gasoline, light fuel oil (such as diesel), and natural gas. It also applies to combustible waste, which includes tires and asphalt shingles. The fuel charge rates reflect a carbon pollution price of $30 per

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[7] EB-2022-0072, EGI Submission, Appendix A

[8] Canadian Biogas Association, 2022. Hitting Canada's Climate Targets with Biogas and RNG. https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf

[9] Greenhouse Gas Pollution Pricing Act, S.C., 2018, C12., S.186. https://laws.justice.gc.ca/eng/acts/G-11.55/FullText.html

[10] Greenhouse Gas Pollution Pricing Act, S.C., 2018, C12., S.186, Part 1, https://laws-lois.justice.gc.ca/eng/acts/G-11.55/page-1.html#h-244007

[11] Greenhouse Gas Pollution Pricing Act, S.C., 2018, C12., S.186, Part 2 https://laws-lois.justice.gc.ca/eng/acts/G-11.55/page-18.html#h-246320

[12] Backstop jurisdictions are those provinces or territories in which the provincial or territorial regulations do not meet the federal benchmark for carbon pricing, and therefore the federal regulations prevail. British Columbia, Quebec, Nova Scotia, Northwest Territories, New Brunswick, and Newfoundland and Labrador implemented their own carbon pollution pricing systems that meet the federal benchmark for both the OBPS and fuel charge. The remaining provinces and territories are subject to the federal backstop pricing for one or both of these benchmarks.

tonne of carbon dioxide equivalent (CO_2e) as of April 1, 2020 rising by $10 per tonne annually to $50 per tonne as of April 1, 2022.[13]

RNG is exempt from the carbon charge as it is not a fossil fuel. The GGPPA does not consider the carbon intensity of a fossil fuel or fossil fuel replacement, such as RNG, in its calculation of the carbon fuel charge. Under the GGPPA, RNG is valued volumetrically for its ability to displace natural gas and the emissions associated with its combustion on a 1:1 basis. This is different than the Clean Fuel Regulations, as noted below, which does account for the carbon intensity of a fuel. Since the GGPPA does not consider carbon intensity, the ability to prevent the release of methane to the atmosphere from various types of RNG (e.g., anaerobic digesters that receive manure or other organic wastes) goes unrecognized and unmonetized.

Clean Fuel Regulations (CFR)

The Federal Clean Fuel Regulations (CFR)[14] was finalized and released in June 2022, where the compliance obligation for covered entities (liquid fuel producers) begins in July 2023. The purpose of the CFR is to lower the carbon intensity (CI) of fuels produced and consumed in Canada. The CFR allows covered entities a variety of means to achieve compliance. Fuels with CI above the regulatory target will generate deficits, whereas low CI fuels will generate credits, and obligated parties must purchase credits or pay into a compliance fund to cover their total deficits. RNG is applicable to two compliance categories: category 2 which increases supply of renewable and low CI fuels, and category 3 is for specified end-use fuel switching in transportation. RNG can create credits even when those fuels are not used in transportation. Category 2 would apply for credit creation under the gaseous class and would be subject to the 10% usage limit. Here, the credit creator would be the producer or importer of the RNG. Credit creation would be based on the CI of the RNG as compared to the reference CI for the gaseous class.[13] RNG used as fuel for a vehicle in Canada could create compliance credits under category 3 for fuel switching applications. Here, the credit creators would be the producer/importer of the fuel and the owner/operator of a fueling station.[13]

Credits can be bought and sold between registered creators and primary suppliers directly for an agreed upon price. The price of credits in the Credit Clearing Mechanism, which is used when obligated parties that have not been able to acquire credit elsewhere and still have a deficit need to acquire credits, has a maximum of approximately $300 CAD/CFR credit of CO_2e.[15] The Compliance Fund Mechanism within the CFR can be used to satisfy a maximum of 10% of the reduction requirements for a given compliance period. Upon contribution to a fund, a primary supplier would receive credits that are non-tradable and non-bankable. The price to create a credit from the CFM is $350 CAD/CFR credit (2022)[14]. A primary supplier would be authorized to carry forward up to 10% of its reduction requirements at 20% annual interest rate, only if there were not sufficient credits in the Credit Clearance Mechanism to satisfy its deficit and it has used its maximum contribution to an emission reduction fund.[14]

Low Carbon Fuel Standards (LCFS)

Clean fuel regulations require fossil fuel suppliers to gradually reduce the carbon intensity of their fuels while allowing for a range of compliance pathways to help them achieve their targets. One permitted tool

[13] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/greenhouse-gas-annual-report-2020.html
[14] *Clean Fuel Regulations* SOR/2022-140, https://www.canadagazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html
[15] *Clean Fuel Regulations* SOR/2022-140, https://www.canadagazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html

is the integration of cleaner fuel alternatives. As a result, depending on how the programs are designed, clean fuel standards can stimulate RNG activity.

British Columbia's (B.C.) Low Carbon Fuel Standard[16], initially introduced in 2008, aims to achieve a 20 percent reduction in the carbon intensity of transportation fuels by 2030. In 2019, RNG was approved for inclusion as a transportation fuel, which sends a positive signal to RNG developers, though confined to its use for transportation. Average credit prices in the B.C. LCFS, have almost doubled since compliance year 2020 with average credit pricing as of July 2022 at \$444.85/tCO_2e[17] For reference, there are two CNG projects (CI scores equals 6.81 gCO_2e/MJ and 10.02 gCO_2e/MJ) listed in the approved carbon intensities table for transportation fuel producers who wish to have a fuel carbon intensity approved for posting and use in British Columbia.[18] At the listed CI scores and average July 2022 cost per credit value, the value per GJ of these projects would be approximately \$3.02 to \$4.46/GJ.

Renewable Gas Mandates

Renewable fuel mandates require fossil fuel suppliers to blend in a minimum percentage of renewable content. This type of regulation has existed at the federal and provincial levels for liquid fuels since 2011. More recently, it has been used at the provincial level for gaseous fuels, with B.C. and Québec both using mandates to require that provincial natural gas suppliers add renewable content to their supplies of conventional natural gas. This in turn has stimulated the adoption of RNG alongside other renewable gases[1].

- British Columbia: B.C.'s emerging renewable gas mandate will require natural gas suppliers to blend at least 15 percent renewable content by 2030.[19]
- Québec: Québec's RNG mandate, implemented in 2019, aims to achieve a five percent renewable blend by 2025 and 10 percent renewable blend by 2030.[20]

In B.C., the BCUC has approved long-term supply agreements (e.g., 10 years) for purchases of RNG by the utility. These long-term purchase agreements are not backstopped by long-term sales agreements. The agreements for RNG supply from out of province as also been approved by the BCUC. Pricing for such supply agreements for up to \$31/GJ (with a 2% annual increase) is approved by the BCUC. Pricing is somewhat related to CI scores, with lower CI score projects attracting higher prices.[21]

Organic Diversion and Landfill Controls

Many provincial governments have regulations governing methane emissions from landfills. Because landfill gas is a major feedstock for RNG energy, these regulations can stimulate RNG development. However, the impact of these regulations is limited by the fact that compliance can often be met through

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16 *Renewable and Low Carbon Fuel Requirements Regulation*, B.C. Reg. 394/2008. https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/394_2008

17 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/monthly_credit_market_report_-_2022-07.pdf

18 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf012_-_approved_carbon_intensities_-_current_-_20220815_v2.pdf

19 Government of British Columbia, 2018. CleanBC: Our nature, our power, our future. See page 66. https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_2018-bc-climate-strategy.pdf

20 Government of Quebec, 2020. 2030 Plan for a Green Economy: Framework policy on electrification and the fight against climate change. See page 84. https://cdn-contenu.quebec.ca/cdn-contenu/adm/min/environnement/publications-adm/plan-economie-verte/plan-economie-verte-2030-en.pdf?1635262991#:~:text=With%20the%202030%20Plan%20for,require%20substantial%20effort%20from%20everyone.

21 https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/102_2012

simple methane collection and flaring, without utilization through biogas and RNG energy. It should also be noted that where regulation requires landfill gas destruction, projects will not be eligible to create offsets and carbon intensity calculations would not recognize the avoided methane from an activity that is required.

- British Columbia: Large landfills producing over 1000 tonnes of methane per year are required to collect landfill gas and flare.[22]
- Manitoba: Three largest landfills are required to collect landfill gas.[23]
- Ontario: Landfills larger than 1.5 million cubic metres of waste disposal capacity are required to collect landfill gas and to flare it or to use it.[24]
- Québec: Large landfills collecting more than 50,000 tonnes of residual materials per year are required to collect landfill gas and to flare it or utilize it.[25]

Offset Systems

Government-regulated GHG offset systems allow credits to be generated by approved activities that voluntarily reduce emissions. These credits can then be sold to firms to help them comply with regulated emissions reduction targets. Offset systems that allow credits to be generated through methane destruction in the waste or agriculture sectors can be effective at stimulating biogas and RNG development so long as they allow utilization through biogas and RNG as an eligible destruction device.[26]

Federal: The Canadian Greenhouse Gas Offset Credit system regulations currently enables project proponents to generate federal offset credits using the Landfill Methane Recovery and Destruction protocol.[27] The protocol allows for either the destruction of landfill gas or the injection of upgraded landfill gas into a natural gas network.

Alberta: The Alberta Emission Offset System allows credits to be generated by biogas and RNG projects – including landfill gas, diverted organic waste, animal manure and wastewater projects – and sold to firms regulated under the TIER (Technology Innovation and Emissions Reduction) regulation.[28]

Québec: Firms regulated under the province's cap-and-trade system can purchase offsets, including through landfill and manure-based biogas and RNG projects.[29]

Under Development: Offset protocols are currently under development by governments in B.C. and Saskatchewan.

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[22] Landfill Gas Management Regulation B.C. Reg 391/2008, https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/391_2008#section7

[23] Canadian Biogas Association, 2022. Hitting Canada's Climate Targets with Biogas and RNG. https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf

[24] *Landfilling Sites* OR232/98, Part III, Section 15. https://www.ontario.ca/laws/regulation/980232

[25] Regulation respecting the landfilling and incineration of residual materials Q-2, R19, https://www.legisquebec.gouv.qc.ca/en/document/cr/Q-2,%20r.%2019%20/?langCont=fr#se:32

[26] Canadian Biogas Association, 2022. Hitting Canada's Climate Targets with Biogas and RNG. https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf

[27] Government of Canada, 2022. Federal Offset Protocol: Landfill Methane Recovery and Destruction, V1.0. https://publications.gc.ca/collections/collection_2022/eccc/En4-461-2022-eng.pdf

[28] Environment and Parks Alberta, 2020. Quantification Protocol for Biogas Production and Combustion. Government of Alberta, https://open.alberta.ca/dataset/e4dadabf-2c60-4cba-8182-2d1f5e360e86/resource/32eba277-cb6d-4615-90c1-86c7f264c63c/download/aep-quantification-protocol-for-biogas-production-and-combustion.pdf

[29] Gouvernement du Québec, 2011. Regulation respecting a cap-and-trade system for greenhouse gas emission allowances, Appendix D – Offset Protocols, https://www.environnement.gouv.qc.ca/changements/carbone/credits-compensatoires/index-en.htm

Canadian Policy Considerations

The CFR is a low-carbon fuel standard type program that, while aiming to lower the carbon intensity of liquid fossil fuels, recognizes the use of low carbon fuels in other applications. The CFR is unique in this aspect, as RNG used to displace natural gas used to heat buildings or to produce power has the ability to create CFR credits that regulated entities can use for compliance. To date, existing low-carbon fuel standard programs only create credits where low-carbon fuels are used in transportation.

In B.C. and Québec, renewable gas content mandates are volumetric and recognize the direct GHG emission reduction benefits of RNG, but do not consider the indirect GHG emission reduction benefits (i.e., take a lifecycle approach that recognizes avoided biogenic methane releases, also known as carbon intensity [CI] of the gas) provided from RNG. The Federal Greenhouse Gas Pollution Pricing Act[30] and the Québec cap and trade system[31] considers RNG in a similar fashion, where the GHG emission reduction benefits reflect only the direct emission reductions and do not vary according to the type of RNG or the indirect GHG emission reductions benefits that are expressed by carbon intensity values.

In Canadian jurisdictions with RNG mandates, the introduction of the CFR should create an additional value stream where the CFR credits from RNG use can be sold to CFR regulated entities (i.e., liquid fuel producers) and CFR credit revenues can lower the effective RNG price. In this context, the carbon intensity of RNG will affect credit creation and revenue potential, where the lower the CI the more CFR credits and revenue can be created, however the carbon intensity of the RNG will have no influence on the direct emission reductions, as recognized in the GGPPA, or achieving the volumetric mandates.

2.2 United States (U.S.)

U.S. policy and RNG markets are more developed than the Canadian markets to date. The data from these markets can be useful for predicting the development of the Canadian market.

Renewable Fuel Standard (RFS)

The RFS[32] is a federal U.S. policy that mandates the blending of biofuels with transportation fuels. An obligated party's requirement, known as Renewable Volume Obligation (RVO), is tracked by the Environmental Protection Agency (EPA) through a tradable credit system known as Renewable Identification Numbers (RIN). Obligated parties must return a certain number of RINs, based on their RVO, to the EPA to prove compliance with the annual standard at the end of the compliance year. The statutory volumes under the RFS are set to expire at the end of 2022, giving the EPA authority to set biofuel blending requirements post-2022 unless new statutory volumes are established through the legislative process. Some members of Congress have voiced support for the replacement of the RFS with a national LCFS program (like California's) that provides incentives for a wider-range of low-carbon fuels (e.g., hydrogen, electricity, biofuels, etc.). There appears to be support for the continuation of the RFS in some form, but

[30] *Greenhouse Gas Pollution Pricing Act*, S.C. 2018, C12., S186. https://laws-lois.justice.gc.ca/eng/acts/g-11.55/
[31] Regulation respecting a cap-and-trade system for greenhouse gas emission allowance, C. Q-2, r. 46.1. https://www.legisquebec.gouv.qc.ca/en/document/cr/Q-2,%20r.%2046.1
[32] 40 CFR Part 80: Regulation of Fuels and Fuel Additives, Subparts K and M https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-80?toc=1

failure to create new statutory volumes after 2022 may introduce uncertainty into RIN markets[33]. Current RIN values as of June 2022 ranged from $1.35 USD for D6 fuel to $3.24 USD for D3 fuel ($1.73-4.14 CAD).[34]

California Low Carbon Fuel Standard

The California Air Resources Board (CARB) approved the LCFS[35] program in 2009, which was designed to reduce the CI of California's transportation fuels by 10% by 2020. The LCFS has been amended and extended to a target of a 20% reduction in CI by 2030. The standard puts a price on carbon in California, with low-carbon fuels generating credits for their carbon reduction, and higher-carbon fuels generating a deficit. A build-out of electrification and other low-carbon technologies also generates credits[36]. Like the Canadian systems, CI scores are key to the LCFS. Current LCFS credit values as of June 2022 ranged from $78 USD to $202 USD per credit ($100-258 CAD), with the average price approximately $113 USD per credit ($144 CAD).[37] This is down from an average high in 2020 of $199 USD per credit ($254 CAD).[38]

The California LCFS market is the most established market to date for RNG. Several other markets are starting to emerge including the Washington Clean Fuel Standard[39] and the Oregon Clean Fuel Standard.[40] In January 2022, the Oregon Department of Environmental Quality (DEQ) announced that it was conducting a rulemaking to propose changes to the Clean Fuels Program regulation. The proposed rulemaking may include expansion of the annual average carbon intensity reduction targets beyond 10% and beyond 2025; modifications to the program that will support achievement of the new standards; and other modifications to improve the effectiveness of the Clean Fuels Program.[41]

The Washington Clean Fuel Standard includes a mandate for a 20% reduction in the carbon intensity of transportation fuels from 2017 levels by 2038 and may begin as early as January 2023.[42]

Midwest Low Carbon Policy

Midwestern Governors Association advisory group on low carbon fuel policy issued a 2010 report[43] recommending a regional approach as a next best alternative to a comprehensive federal policy. The report recommended a 10 % reduction in 10 years. No Midwest state has adopted a LCFS in response.[44]

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[33] Per. Comm. 2022. Faizal Hassan, Director Environmental Products, Anew Climate. June 22, 2022.
[34] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information
[35] Assembly Bill 32. Chapter 488, (California, 2009) http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf ,and Executive Order S-01-07, http://gov.ca.gov/executive-order/5172/
[36] RBC ESG 2020 report
[37] Monthly LCFS Credit Transfer Activity Report for June 2022. https://ww2.arb.ca.gov/sites/default/files/2022-07/June%202022%20-%20Monthly%20Credit%20Transfer%20Activity_0.pdf
[38] Monthly LCFS Credit Transfer Activity Report for December 2020. https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/credit/December%202020%20-%20Monthly%20Credit%20Transfer%20Activity.pdf
[39] Transportation Fuel -Clean Fuels Program Chpt 70A.535, https://app.leg.wa.gov/RCW/default.aspx?cite=70A.535
[40] Oregon Clean Fuels program, OAR Chpt 340, division 253, https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=1560
[41] https://www.oregon.gov/deq/rulemaking/Pages/cfp2022.aspx
[42] Canadian Biogas Association, 2022. Hitting Canada's Climate Targets with Biogas and RNG. https://biogasassociation.ca/images/uploads/documents/2022/resources/Hitting_Targets_with_Biogas_RNG.pdf
[43] LCFS Working Group, 2010. Midwestern Low Carbon Fuel Standard Working Group Final Recommendations https://secureservercdn.net/166.62.108.196/8jk.4e3.myftpupload.com/wp-content/uploads/Events/LCFP/FinalRecommendations.pdf
[44] https://www.rngcoalition.com/policies-legislation-1

Northeast/Mid-Atlantic Clean Fuels Standard

Governors of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont signed a 2009 memorandum of understanding committing to develop a regional low carbon fuel standard.[45] All states have adopted laws to achieve 80% reduction from 1990 levels of GHG emissions. A regional LCFS has not been adopted. Efforts continue with policy support from Northeast States for Coordinated Air Use Management.

Regional Greenhouse Gas Initiatives (RGGI)

RGGI was established in 2005 and operates as a regional cap-and-trade program for CO_2 emissions from power plants. Electricity generating units with a nameplate capacity over 25 MW (15 MW in New York) are required to comply with the cap and procure CO_2 allowances or offsets. Agricultural manure management (RNG production) and landfill methane capture are two qualifying project activities that provide CO_2 offset allowances based on avoided methane emissions. While CO_2 allowance prices have risen in recent months due to increased speculative activity (from $8 USD in Q2 2021 to $13.50 USD in July 2022 [46]), historically low prices coupled with the requirement that projects must be located in a RGGI state has resulted in only limited interest in offset development. Members of the RGGI include Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Virginia, and Vermont.[47] Pennsylvania also has a RGGI rule in place, but linkage with the program is delayed due to court cases.

Renewable Gas Mandates

In February 2022, the California Public Utilities Commission (CPUC) announced a renewable gas mandate that applies to California's four major natural gas distributors as well as its many smaller ones.[48] The California mandate is specific to biogas-sourced RNG, as opposed to hydrogen or biomethanized RNG, and requires a 12.2% minimum renewable blend of the utility's own share of 2020 annual bundled core customer natural gas demand by 2030. Dairy methane is limited to 4% of the medium-term procurement obligation. The Commission's Energy Division will process individual contracts to procure biomethane through a three-tier advice letter approval process: Tier 1 for contract prices up to $17.70 USD/MMBtu; Tier 2 for contract prices between $17.70 and $26 USD/MMBtu[49]; and Tier 3 for contract prices above $26 USD/MMBtu.[49] A modified GHG, Regulated Emissions and Energy Use in Technologies (GREET) model will be used to determine CI scores of proposed projects. Utilities are directed to report CI scores in their advice letters to the CPUC seeking approval of a procurement contract. The CI score for purposes of procurement will be used for contract review and procurement decisions. However, the CI score can change as production facilities change; thus, ongoing CI score management will be subject to review.[50]

[45] Northeast and Mid-Atlantic Low Carbon Fuel Standard Memorandum of Understanding, 2009. https://www.nescaum.org/documents/lcfs-mou-govs-final.pdf/https://www.nescaum.org/documents/lcfs-mou-govs-final.pdf/
[46] Market Monitor Reports. https://www.rggi.org/auctions/market-monitor-reports
[47] https://www.rggi.org/program-overview-and-design/elements
[48] Senate Bill 1440 (California, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF
[49] 1 MMBTU equals 1 Dekatherm
[50] CPUC, 2022. Decision Implementing Senate Bill SB1440, Biomethane Procurement Program. Rulemaking 13-02-008 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF

Renewable Portfolio Standards (RPS)

A RPS is a law that requires retail electricity suppliers to generate a minimum percentage of their electricity using eligible renewable energy sources. Twenty-nine (29) States and the District of Columbia have mandatory RPS laws. Seven States have non-binding goals. No two RPS laws are the same. A typical law includes a percentage and a date to be met. For example, the Renewable Portfolio Standard in California requires municipal and investor-owned utilities to generate 60% of their energy from renewable sources by 2030.[51] Interim annual targets are required with three-year compliance periods and 65% of RPS procurement is to be derived from long-term contracts of 10 years or more. RPS mandates are often backed by penalties for non-compliance and statutorily limit the impact on the consumer's rate (most below 10%, 13 States below 5%).[52] Generating electricity from renewable sources like RNG helps states meet their RPS policy goals of ensuring stable, diversified energy portfolios that are not overly dependent on fossil fuels.

[51] Renewable Portfolio Standards Program
https://www.cpuc.ca.gov/rps/#:~:text=California's%20RPS%20program%20was%20established,a%2050%25%20RPS%20by%202030.
[52] https://www.eia.gov/energyexplained/renewable-sources/portfolio-standards.php

3.0 Existing Green Energy Programs

The desire to decarbonize by industry, commercial entities and residential consumers has given rise to demand for RNG across North America. Aside from the regulatory-driven and mandatory compliance markets, the voluntary market for RNG is also broadening and expanding.

In some cases, larger industrial firms invest in RNG production plants or arrange counterparty purchases from producers and wholesale marketers. Larger commercial entities often do likewise. For example, Shell Oil Products U.S., a subsidiary of Royal Dutch Shell plc., has successfully achieved the start up and production of RNG at its biomethane facility in Oregon.[53] Residential consumers are also increasingly able to access RNG supplies via their local gas distribution utilities.

The demand-pull at the residential and commercial levels for RNG supply is like earlier demand pull and adoption by these same customer groups for renewable electric power. Some customer groups are also seeking to voluntarily purchase carbon offsets to advance their decarbonization ambitions beyond renewable electricity or RNG.

Marketers and utilities are devising product packages that afford opportunities for customers to purchase these environmental assets and are useful for decarbonization across North America. Anew has undertaken a survey of these utility programs which is presented from publicly available sources surveyed in the table provided in Appendix A. The highlights of these programs have been summarized below.

3.1 Program Highlights

Program size: Of the top 15 largest residential distributors in the U.S., with populations served between 745,000 and 5.5 million, and distributed natural gas volumes between 54 PJ and 242 PJ[54], six companies have RNG programs in place and/or have recently proposed programs. The majority of the remaining companies within the top 15 make some mention of using RNG and/or are actively pursuing procurement of RNG, but do not have residential and/or commercial programs in place. In Canada, gas utilities with RNG programs in place include Enbridge Gas, FortisBC, and Énergir. Other residential gas distributors such as APEX Utilities, Medicine Hat, or SaskEnergy, do not currently offer RNG to residents. Both SaskEnergy and APEX Utilities have indicated they are exploring ways to provide RNG to customers.[55,56]

Many of the companies that have voluntary RNG programs have much smaller residential and/or commercial gas volumes than Enbridge Gas (e.g., Vermont Gas, Black Hills Energy, NW Natural, Puget Sound etc.[57]) and the ability to secure larger percentages of their total natural gas demand is simplified due to these smaller required volumes. For example, Vermont Gas has 4.1 billion cubic feet (bcf) per year (4.3 PJ) in residential distribution with approximately 46,400 residents.[58] It was aiming to achieve 25,000 Mcf (0.3 PJ) of RNG, or 7% of residential natural gas demand in 2020.[59]

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[53] https://www.shell.us/media/2021-media-releases/shell-starts-production-at-shell-new-energies-junction-city-its-first-us-renewable-natural-gas-facility.html
[54] https://www.aga.org/contentassets/d68b868b7cd94ed2889b704b441ab469/1002resvol.pdf
[55] https://online.flippingbook.com/view/782040202/28/
[56] https://www.apexutilities.ca/safety-sustainability/hydrogen-renewable-natural-gas/
[57] https://www.aga.org/contentassets/d68b868b7cd94ed2889b704b441ab469/1002resvol.pdf
[58] Vermont Gas is the only natural gas distribution company in the State. https://www.aga.org/policy/state/natural-gas-state-profiles/VT/
[59] Vermont Department of Public Service, 2021. 2021 Annual Energy Report: A summary of progress made toward the goals of Vermont's Comprehensive Energy Plan, Pg 34
https://legislature.vermont.gov/Documents/2022/WorkGroups/Senate%20Natural%20Resources/Reports%20and%20Resources/W~Ed%20McNamara%20~Annual%20Energy%20Report%202021%20DPS~1-15-2021.pdf

Voluntary or mandatory: Of the programs surveyed, there is a mix of both voluntary and mandatory use of RNG. Where there is mandatory use of RNG due to renewable portfolio standards or renewable gas mandates in place, some utilities are also providing voluntary programs to residential consumers in addition to the mandatory incorporation of RNG to the system (e.g., FortisBC). Based on a review of program applications, it appears that voluntary programs are generally proposed over mandatory programs. These programs allow customers the choice in the dollar amounts they want to pay for the service.

The proposed FortisBC program is a combination of voluntary and mandatory.[60] The proposed program provides mandatory delivery of 100% RNG to all new residential dwellings. Customers will pay a low carbon gas charge equal to the combination of the commodity cost recovery charge plus carbon tax - which is the equivalent rate as other gas customers. Another mandatory aspect of this program is the Renewable Gas Blend for sales customers under which all customers who purchase gas from FortisBC will be provided a base level of RNG as part of their regular gas service, subject to supply. FortisBC expects to begin this as a 1% blend on January 1, 2024. The blend will increase over time to enable the company to meet the provincial GHG emissions targets. FortisBC also has an existing voluntary program offering customers the option to purchase up to 100% RNG to meet GHG emission reduction targets. This helps customers that need to reduce their GHG emissions to meet internal or externally imposed targets. This combination of voluntary and mandatory programs enables long-term contracting for RNG and achieving a larger percentage of RNG into the system than a voluntary program on its own. The inclusion of a voluntary component allows those customers that have GHG reduction goals to increase their purchase of RNG beyond the mandatory volumes provided by the utility.

Optionality: In the voluntary green programs being offered, program delivery is generally a similar structure across utilities where customers are given the option of a fixed dollar amount or a fixed percentage of RNG that offsets a portion of their monthly natural gas use with RNG (e.g., 1% to 100% of their natural gas use replaced with RNG[61], or $10 per month for RNG[62], see Appendix A), or customers can pick the dollar amount and equivalent percentage of GHG emissions reductions they would like to pay for (e.g., $4 per month that may offset 25% of their natural gas emissions[63], see Appendix A). Some programs give a single price for the program and others give a range of prices the customer can chose from. For example, Enbridge Gas charges a single price of $2 per month for their RNG program[64] versus Puget Sound Energy where customers can start at $5 per month and pay as much as they would like to incorporate RNG[65]. The average lower end price for programs is approximately $5 per month, although the associated quantities of RNG that this translated into for each program differed depending on how their program costs are calculated and the price paid for RNG. For example, Dominion Energy has $5 blocks that equate

[60] FortisBC, 2021. Letter to BCUC, re: Biomethane Energy Recovery Charge (BERC) Rate Assessment Report -BCUC Order G-35-21 https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf
[61] Gazifère website: https://gazifere.com/en/renewable-natural-gas/#:~:text=Gazif%C3%A8re%20is%20proud%20to%20present,sites%20and%20water%20treatment%20plants.
[62] CPUC, 2020. Decision Adopting Voluntary Pilot Renewable Natural Gas Tariff Program. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M349/K624/349624040.PDF
[63] DTE Website: https://solutions.dteenergy.com/dte/en/Products/DTE-CleanVision-Natural-Gas-Balance-LVL-1/p/NATURAL_GAS_BALANCE_LEVEL_1
[64] Enbridge Gas Website: https://www.enbridgegas.com/sustainability/optup
[65] Puget Sound Energy Website: https://www.pse.com/green-options/Renewable-Energy-Programs/Renewable-Natural-Gas-Business

to 0.5 therms per month of natural gas use that is replaced with RNG[66], Avista Energy has $5 blocks that equate to 1.5 therms per month of natural gas use[67], and Blackhills Energy has $5 blocks that equate to 20.5 therms per month of natural gas use. Most often these programs do not require the physical delivery of RNG in the pipeline. The utilities will purchase the green environmental attribute associated with the RNG that is required. Therefore, the 'block' that is being purchased is the cost for delivery of a specified quantity of environmental attributes for RNG, equivalent to the amount of natural gas that would have been purchased.

Type of green energy procured: Several of the utilities use a combination of RNG and carbon offsets in their program offering for zero carbon natural gas. The mix of RNG to offsets is largely at 5% RNG and 95% offsets, although in a few cases utilities are using or trialing 10% and 90% or 1% and 99%, or 100% offsets. Some notable programs that use RNG only are the SoCal Gas program and the FortisBC program. In most cases where a combination of RNG and offsets are being used, the RNG is being supplied through contracts with marketers who carry a portfolio of RNG directly with RNG producers. In most cases the physical delivery of the RNG is not a requirement, and so the environmental attribute of the RNG is purchased through book and claim type systems. The M-RETS program for tracking and verifying the renewable thermal credit associated with the RNG was proposed and/or is used in several programs to provide transparency and credibility to the environmental attribute. The transparency and verification of RNG is an element that appeared to be important to several of the commissions when evaluating the RNG program applications.[68] Although physical delivery was not a requirement in most programs, there was a desire to support local sources of RNG where possible which was encouraged by commissions as part of their program approvals.[69]

Where the information is available publicly, the carbon offsets are purchased from one of the four main voluntary carbon registries including Verra's Verified Carbon Standard (VCS), Gold Standard, Climate Action Reserve (CAR), and/or American Climate Registry (ACR). These are considered reputable registries that provide real, verifiable, enforceable, permanent, and additional carbon projects. Some utilities explicitly indicate a preference for offset projects that are locally sourced from nature-based projects, while others highlighted their financial support for projects in developing countries with their offset purchase. Transparency regarding where the projects are located and how they are tracked and verified is a common theme to many of the programs as this helps to ensure that stakeholders are adequately informed as to where their funds were going.

Carbon intensity of RNG is generally not a characteristic that is discussed in the green energy program applications. If the program is being done for voluntary carbon reduction purposes, GHG accounting through the World Resources Institute (WRI) GHG Protocol would allow for the RNG to be accounted for as zero carbon emissions (depending on the gas type). If the gas is considered to have a negative carbon intensity, this may be accounted as avoided emissions in the inventory.[70]

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[66] Dominion Energy website: https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/utah/greentherm/2020-annual-greentherm-program-report-6-30-2021.pdf?la=en&rev=cecbe954c6174f6791313e8ee96daeee

[67] Avista Energy website: https://www.myavista.com/energy-savings/green-options/renewable-natural-gas#:~:text=Avista's%20RNG%20program%20supports%20RNG,purify%20it%20to%20make%20RNG.&text=Check%20out%20our%20FAQs%20to,program%20and%20its%20many%20benefits.

[68] https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_790732,

[69] https://epuc.vermont.gov/?q=node/104/16215/FV-Legacy-EXHDOX-PTL

[70] https://ghgprotocol.org/sites/default/files/standards/Product-Life-Cycle-Accounting-Reporting-Standard_041613.pdf

Program Characteristics: RNG voluntary programs are generally on a cost recovery basis, where the cost is recovered by the participants and not through the entire customer base. This was generally the case for programs where the mix of RNG and offsets were being offered. Deferred accounting for programs was identified in two programs to manage high initial administrative costs. For example, the Blackhills program proposed in Colorado is requesting a deferred accounting mechanism to give the company an opportunity to recover the deferred costs in the future as program participation increases. In this case, Blackhills indicates in the early years of the pilot the anticipated expenses associated with upfront marketing costs in acquiring new participants are greater than the anticipated revenues due to low initial participation. The imbalance is expected to result in expenses exceeding revenue. In subsequent years, increased enrollees could generate revenue more than program expenses, creating a regulatory liability. If the program becomes over-collected, the company will use the excess revenues to benefit program participants by either acquiring more RNG and/or higher premium carbon offsets which would increase the CO_2 emissions offset with each block enrolled. The FortisBC program currently allows for distribution of costs across the entire utility customer base, thus the program does not need to be on a cost recovery basis, allowing for greater purchase ability by the utility. FortisBC has used this cost recovery certainty to secure long-term contracts with many RNG producers.[71] Several of the proposed programs were investigating the potential to sell the environmental attributes associated with gas that was procured but not required by the voluntary program users each year. This would allow for some cost recovery and help to smooth out program costs.

Marketing/Administration Expenses: Comparison of marketing expenses could not be done across all programs as many of the program costs were redacted from public documents or were not provided. Of those that were provided, there was a considerable range in costs associated with the programs and the type of costs included. SoCalGas estimated the marketing costs for the first 5 years of their program will be approximately $330,000 USD, starting at $90,000 USD in year one and $60,000 USD per year thereafter.[72] No estimate of quantities of RNG associated with the program were given to determine the percentage of marketing dollars spent per unit of RNG procured. Blackhills Gas in Colorado estimated their marketing costs will range from $87,500 USD per year to $119,750 USD per year for approximately 2900 customers out of 195,000 total eligible customers.[73] In the first year of the program they anticipate displacing 174,363 therms of natural gas; however, the cost RNG and offsets were not given to determine the percentage of marketing dollars spent per RNG procured. Dominion Energy estimated the total expenses to admin ratio for the first two years of their RNG program (2020-2021) went from 19% to 4% as new participants were added to the program.[74] DTE's 2021 Annual Report indicates their total program costs were approximately $1,221,685 USD of which 4,211 tCO_2e was procured as offsets at a cost of $33,685 USD, and 4,044 mcf of RNG was procured at a cost of $127,652 USD. Direct marketing costs were approximately $775,000 USD. Of the total cost of the program only 10% of the budget went to the procurement of RNG.[75] These final two examples suggest that marketing expenses associated with

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[71] Table 6-1, https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf

[72] Chapter 7: Grant Wooden Program Design, https://www.socalgas.com/regulatory/A19-02-015

[73] Hearing Exhibit 101 -Attachment MJC-1, https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_790732

[74] Dominion Energy, 2022. 2021 Annual GreenTherm Program Summary Report. Docket No. 19-057-T04. June 30, 2022.

[75] DTE, 2022. DTE Gas Natural Gas Balance (NGB) U-20839, Program Update and 2021 Annual Report, March 18, 2022. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000002U2pfAAC

voluntary programs may consume a large portion of the budget that could be used for procuring additional RNG into the system.

Procurement Strategy: Details of procurement strategies including the timing of purchases, the long- and short-term commitments, and the prices paid for each green energy product were generally not provided in the public applications or hearings documents as this is often proprietary information that producers and marketers do not want disclosed in public documents.

Some programs, such as Vermont Gas, noted that if they were not able to procure enough RNG supply at a given time, they would purchase equivalent carbon offsets to meet demand. This, however, would only last for 30 days, after which time the company would notify customers of the shortage and options going forward.[76] Vermont Gas also noted that for any excess RNG not sold under the program, they may market the carbon offsets or any other available environmental attribute relating to RNG and revenues generated would be used to offset the cost of the RNG program. This flexibility would tend to allow Vermont Gas to increase its purchased volume. Like the lever of longer-term contracting, purchasers of higher volumes of RNG may realize more favorable discounted pricing terms from RNG sellers.

[76] https://epuc.vermont.gov/?q=node/104/16215/FV-Legacy-EXHDOX-PTL

4.0 Structural Overview of the North American RNG Market

North America has an active renewable natural gas ecosystem. RNG supply is produced at several types of facilities that capture methane resulting from the decomposition of biological wastes. Demand for RNG is growing in several key sectors to drive development of supply. With adequate processing and access to injection points and required approvals, RNG can be injected into the vast North American natural gas pipeline grid.

The interconnected pipeline network serving North America transports natural gas and RNG on the concept of "delivery by displacement" and "book and claim" transaction. North American gas market producers can inject and book RNG molecules at one point of the North American network that can be delivered and claimed by consumers elsewhere. This ability to move RNG across the continent or multiple jurisdictional borders is a great advantage in drawing supplier project capital and assuring consumers can access RNG decarbonization benefits.

- **Reliance on Bilateral Deals:** Most producers and project developers seek the highest value for their product with the lowest risk by seeking to serve the highest value market on a long-term basis with the greatest volume. To do so, supply projects must line up consumption and offtake agreements. These are often done independently and over the counter by the project operator or in concert with third-party environmental attribute marketers and brokers. Exchange trading of RNG as a renewable commodity has recently become a reality on the M-RETs exchange via Renewable Thermal Certificates (RTC). These RTCs are one dekatherm units of RNG (1.055056 GJ) with fully specified properties including product parameters, carbon intensity scores, and more. In rulemaking documents for California's Senate Bill 1440, the California Public Utility Commission (CPUC) ordered utility buyers of RNG to require their contracted producers to track RNG injections with the M-RETs platform as a default.[77] After weighing submitted comments by RNG producers that clearly expressed a preference for long-term duration contracts of between 10 and 20 years, the same CPUC document included an order stating that RNG procurement contracts can be no longer than 15 years. In a recent investor call, one publicly traded RNG producer noted their commercial business plan seeks to lower RNG transportation market and pricing risks by selling 60 to 70% of production at discounted stacked prices under long term contracts to investment grade stable parties. They also noted they hold the remaining portion at risk for spot market transportation transactions which may offer upside price potential.[78]

- **Roadway Transportation Sector as RNG Primary Driver:** Most current North American RNG demand originates within the transportation market amid compliance requirements for transportation decarbonization. The highest value for RNG is therefore often found in the transportation markets where RNG is prized for deep decarbonization properties as recognized by regulatory compliance programs for both direct and indirect emissions. These programs exist in multiple jurisdictions and at both national and regional levels. (See below for more on California LCFS, B.C. LCFG, U.S. RFS, and Canadian CFR, etc.). Given the current level of supply and demand, the California transportation marketplace is often the target of North American RNG project developers across the continent. The

[77] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF
[78] https://ricespac.com/wp-content/uploads/2021/04/Rice-Acquisition-Corp.-Archaea-Energy-Investor-Presentation-Transcript-04.07.2021.pdf

California market can be reached easily via the use of existing book and claim accounting and continental pipeline infrastructure.

- **Life Cycle Carbon Intensity Drives Compliance Value:** Unlike voluntary green gas programs, existing regulatory programs set the carbon value for RNG based on its lifecycle carbon intensity as a low carbon volume fuel which can be flexibly used in existing natural gas engines. RNG produced from specific feedstocks and utilizing acceptable production protocols with quantifiable life cycle carbon performance from producer to consumer can be deemed to qualify for credits. For example, the U.S. RPS sets volumetric targets for the usage of various renewable fuels, and credits are granted for the fuels based on volume supplied and consumed. Fuels can also be valued on a sliding scale with life-cycle CI scores representing the amount of carbon embodied and released in a unit of energy contained within the fuel. RNG fuels with lower carbon intensity afford higher decarbonization compared to a conventional fossil fuel baseline. The lower the CI, the higher the value, as shown in Table 4.1.

Table 4.1: California LCFS Transportation Credit Value vs Federal RIN Value Elsewhere

	Swine Farm RNG	Dairy Farm RNG	Food Waste RNG	Landfill RNG
Federal RNG Value in RIN / RFS Program	**$36.47/MMBtu** (Includes D3 on 5/18/22)	**$36.47/MMBtu** (Includes D3 on 5/18/22)	**$36.47/MMBtu** (Includes D3 on 5/18/22)	**$36.47/MMBtu** (Includes D3 on 5/18/22)
State RNG Value in California LCFS Program,	**$74.82/MMBtu** (Includes RFS+ LCFS on 5/18/22 with -400 CI)	**$58.81/MMBtu** (Includes RFS+ LCFS on 5/18/22 with -200 CI)	**$42.81/MMBtu** (Includes RFS+ LCFS on 5/18/22 with 0.0 CI)	**$40.24/MMBtu** (Includes RFS+ LCFS on 5/18/22 with +32 CI)

Source: Anew Advisory representations of Argus 05/18/2022 price per Jaffe et al method

- **Calculations Methods for Stacked RNG Value:** Natural gas, renewable or otherwise, always has a thermal value. But RNG can have additional value if it qualifies for various credits and incentives in overlapping compliance markets. For instance, a volume of RNG sold in California can reap the value for thermal energy, the federal RFS credit, and the state LCFS value. We illustrate with this example:
  - The value of natural gas as an energy source provides the base starting value for stacked RNG valuations. For example, if the fossil fuel energy value of natural gas in the California market is $USD 9.00/MMBtu, then the RNG sold in that market should also get that same value since it is of pipeline quality and chemically identical.
  - To that fossil price, the environmental value of the RNG under the US Federal RFS and can be calculated independently and added in. The RFS value for RNG is based on RIN market values. RIN values are quoted in $USD/gallon but can be converted into $USD/MMBtu. Cellulosic RNG is valued with D3 RINs. Other RNG types made from sugars, fats and other non-cellulosic biologic feedstocks are typically valued with lower-cost D5 RINs. To convert the $/gallon price of a RIN to $/MMBtu for RNG sales, a multiplier of 11.727 is used.[79] That is, if a D3 RIN costs $USD 1.00/gallon in the market, then spot buyers of cellulosic RNG that qualifies under the RFS program would generate credit worth $US 11.72/MMBtu. Non-cellulosic RNG is produced from non-cellulosic waste sugar beet

[79] https://www.rngcoalition.com/calculators-conversions

feedstocks, for example. If we see that D5 RINs costs $USD 0.75/gallon, then the RSF value of the D5-compliant RNG would be $USD 8.80/MMBtu.

- To the fossil and Federal RFS price, an additional credit for qualifying gas used in California can be realized under the state LCFS program. The LCFS program awards credits to transportation operators utilizing fuel with delivered carbon intensity below a reference value relevant to the fuel. For gaseous fuel, the California LCFS program uses a reference base CI value of 79.21 gCO_2e/MJ for pipeline-delivered fossil gas that is compressed and used in CNG vehicles[80]`. Using that, we can determine the LCFS value of a hypothetical RNG from a project whose California market delivered CI, as certified by CARB, is 59.21 gCO_2e/MJ. A vehicle driving in California on this fuel would be counted as abating 20 gCO_2e/MJ of CO_2 equivalent on an energy unit basis. Yet LCFS credits are priced in $USD/tonne of CO_2 equivalent abated. The application of appropriate unit translation factors (1000000 grams to 1 tonne and 1055 MJ to 1 MMBtu) onto the pathway's RNG abatement allows the determination of the RNG under the LCFS program in $/MMBtu[81]. So, for an $80/tonne LCFS credit value, the use of this low carbon RNG would be rewarded with $USD 1.69/MMBtu in LCFS credit value.
- The stacked fossil thermal energy and both federal and state environmental values would sum up in this example to a spot price of $USD 22.40/MMBtu. If the RNG of the same CI and LCCFS value could only qualify for D5 RINs, then the stacked value would be a lesser spot price of $USD 19.49/MMBtu.

- **RNG is More Than a Motor Fuel:** Where simplicity is favored, or where gas processing and/or pipeline injection is unavailable or infeasible, RNG is also used outside of the transportation sector Similar to natural gas, RNG is used to generate power or heat for local purposes. The B.C. LCFS awards value for uses of RNG to displace natural gas used in building heat or power generation uses. Applications range across agriculture, university or district heat, renewable electric power generation, and other valuable purposes. RNG demand can be collocated with an RNG production project site or may be interconnected by midstream logistics. The interplay between the RNG project's development timeline, partner contributions, and contractual relationships are illustrated in the arrangements disclosed between Vermont Gas and Middlebury College, and one RNG project operator.[82]

- **Transportation Markets Change:** Each year, transportation markets tend to see a wave of newer compliance requirements that mandate more stringent decarbonization ambitions. Technological change adds its own dynamism to transportation fuel markets. For example, renewable diesel producers are investing and building out substantial capacity to fuel transportation with lower carbon impact. Manufacturers of electric vehicles, batteries, and charging point technologies are commercializing more choices and capacity. Compliance obligations face periodic resets and grants of waivers. Each drive further changes into the renewable fuels marketplace.

[80] See table 7-1, https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf
[81] See Table 12 in Jaffe et al in The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, June 2016, Institute of Transportation Studies Univerisity of California - Davis, Report UCD-ITS-RR-16-20. https://steps.ucdavis.edu/wp-content/uploads/2017/05/2016-UCD-ITS-RR-16-20.pdf
[82] Middlebury College and Project Partners Celebrate Groundbreaking for Facility That Turns Manure and Food Waste into Renewable Energy | Middlebury News and Announcements

- **Fuel Markets Offer Innate Volatility**: On top of those compliance dynamics, underlying variability in fuel demand is seen to play out in the transportation markets from season to season and year to year. The appetite for transportation fuel is influenced by the economic cycle, consumer spending capacity and appetite for travel overall. For producers selling RNG into transportation compliance markets, and for transportation fuels providers vending into these markets, RNG price volatility and cyclicality are a well-known fact.

- **Pre-Compliance Mandates**: Beyond roadway transportation, other broader transportation market decarbonization rules are pending. Decarbonization efforts are underway in major jurisdictions within the aviation and the marine industries. Participants on both transportation value chains are devising techniques and technologies to utilize RNG as a drop in fuel or as a feedstock for other advanced low carbon transport fuels.

- **Carbon Intensity Varies by Project:** In supplying RNG to a consuming region, each step in the RNG supply chain influences carbon content of the RNG. Energy is used and CO_2e footprints can swell from producer to processor and through long-haul logistics and ultimately in the last-mile distribution and consumption. Each link in the value chain introduces and embodies varying levels of carbon emissions within the product. Due to differing production, processing, and logistics pathways, not all RNG has the same carbon intensity at the meter.

- **RNG CI Starts with Supply**: Unless produced in a gasifier or other advanced methods, most commercially available RNG results from the managed decomposition of waste biologic materials in landfills, wastewater treatment plants, and in masses of agricultural waste. RNG that has been produced from waste is "biogenic", as it came from, and is going to return to, the natural biological cycle involving growth and decay. Biologic waste materials at one time were alive and the carbon and CO_2 within were part of the normal biogenic natural climate. That is one of the fundamental premises as to why the combustion of RNG is considered renewable and carbon-zero fuel. As biogenic methane burns, its direct combustion releases no new anthropogenic CO_2 emissions which result from the combustion of produced geologic gas. For greenhouse gas programs that seek reductions in carbon emissions from a baseline, the lifecycle CI of RNG would incorporate the direct carbon neutrality of biogenic fuel combustion. But CI-based programs also would include production chain effects including feedstock handling, processing, pipeline logistics, leakage and even avoided emissions. Conversely, many compliance programs value and recognize only the direct combustion decarbonization properties of RNG. This includes the current Canadian federal GGPPA that collects zero tax on a 1:1 basis for each volume of fossil fuel switched out with biomethane regardless of its lifecycle carbon intensity. Under the GGPPA, for instance, RNG CI scores do not add or detract from the 1:1 tax abatement afforded by using RNG that meets the program definition of biomethane.

- **RNG Utilizes North America's Pipeline Infrastructure:** Book-and-claim transfers of the environmental attributes and the physical volumes of RNG have become the norm. Using North America's vast pipeline infrastructure, RNG may be produced and processed in one part of the continent, injected into a pipeline locally, and claimed by any consumer with a deliver point meter and the willingness to pay for both the physical commodity and the environmental attribute.

FIGURE 4.1: RNG Market Reached by North American Pipeline Network

Source: US Energy Information Administration (EIA)

- **RNG is Biogenic and Carbon Neutral when Combusted**: During the growth of plant material, carbon becomes sequestered within their leaves, cellulose, and woody structures. Later, the unused plant matter decays naturally or is harvested as trees and crops to become wood products, paper, food, and more. As biogenic material decays after its natural or service life, methane is produced where it is allowed to decompose anaerobically. Forest fires, field burns or other events that combust plant material do emit carbon but only that which was biogenically sequestered originally. Similarly, the combustion of biogenic methane does emit CO_2, but it is considered biogenic CO_2 rather than anthropogenic CO_2.

- **RNG Can Be Carbon Negative:** The investment in and operation of RNG collection facilities at landfills, wastewater treatment plants and farms prevent the escape of biogenic methane. Although zero anthropogenic CO_2 is emitted if successfully combusted, any uncombusted methane released into the atmosphere causes climate warming. Methane is seen to be a potent greenhouse gas that warms the climate several times more deleteriously than even pure carbon dioxide. If producers capture biogenic methane and this RNG displaces non-biogenic fuels, then combusting waste derived biogenic RNG can be seen not only as a zero carbon fuel but also a carbon negative gas substitute.

- **Modelling CI for RNG:** Jurisdictional regulations determine which modelling methodologies are acceptable and whether avoided emissions are recognized or not. Each jurisdiction chooses the calculation tools and approaches which set the foundation for the RNG CI. The major software tools used by producers and their engineers or marketing partners for CI modelling include Canada's

GHGenius model, the Canadian FUEL-LCA tool for the Canadian Clean Fuel Regulation the Argonne National Labs GREET model, or the California LCFS lifecycle pathways incorporating the CA-GREET model. All of these models include negative or avoided emission in calculated RNG CI values. These then form the basis for resulting RNG credit valuation that producers can expect. The lower the CI, the higher the value in CI-dependent regulatory compliance and incentive programs. Higher value for lower CI is also seen in voluntary buyers that seek to abate GHG emissions and meet voluntary GHG reduction targets. Even in jurisdictions that currently value only volumetric performance of RNG in zeroing out direct emissions, the use of RNG with lower CI should have more longevity as decarbonization ambitions advance and low carbon fuel blend rates escalate.

- **Different RNG LCA Tools**: On top of non-uniform jurisdictional views on avoided emissions, RNG values and CIs are often differentiated among types and jurisdiction because of life cycle analysis tools. Each methodology, pathway to market, and calculation tool will show different CI impacts for the waste handling, production process, processing, and logistics of converting waste into marketed fuel. A local project may incur a higher impact from carbon-intensive power used during production, for example, but may have access to shorter pipeline pathways to market that can limit carbon impact of logistics.

- **RNG Flexibility:** Entities across the economy are seeking decarbonization under voluntary and compliance initiatives. RNG can be marketed to enable the decarbonization of gas consumption at all levels including within residential, commercial, and industrial accounts. Heat, power, and steam can be produced with RNG equally as well as with geologic natural gas. But because RNG is so flexible, any RNG consumer must meet or beat the prices set for the market. And the current market setting prices are in the regulated transportation compliance markets that value RNG for its deep decarbonization properties. Some jurisdictions also award credits for renewable power produced by combusting RNG. Yet these power credits are typically valued lower than those in transportation compliance markets.

RNG offers consumers across the economy a highly effective decarbonization fuel and feedstock that is readily useable in essentially all the same applications, with the same infrastructure and uses currently served by geologic natural gas. RNG use can lower corporate scope emission tabulations for reporting purposes and reduce the footprints of delivered goods to trading partners. Potential RNG demand reaches across the economy and into every area served by geologic natural gas.

Currently, the growing RNG producer network can deliver just a fraction of overall natural gas volumes being consumed in North America. All RNG that is destined for pipeline use must be processed to pipeline quality specifications. The complexity of processing and requisite capital costs is incurred no matter the project size (permits, electrical substations, land procurement, etc.) While larger RNG projects can spread fixed investment costs across more RNG volumes, smaller projects can not. This has limited development of many smaller and marginal-volume RNG producing opportunities. But as policies are put in place to recognize the full array of RNG benefits – namely, avoided emissions via CI programs that reward the avoidance, capture and use of biogenic methane otherwise off gassed, then more RNG supplies can be economically produced, valued, and supplied even at smaller scale. This will expand the availability of the most potent forms of carbon-negative RNG that can then decarbonize more of the North American economy.

Book and claim deliveries of RNG through the interconnected North American pipeline network minimizes the carbon footprint of transporting and distributing RNG. Consumption of RNG can be not only carbon neutral but carbon negative as well. In addition to transportation market uses, RNG can be used in building heat and in industrial facilities such as chemicals, steel and refining that utilize methane molecules for both feedstock and thermal fuel.

5.0 Factors Affecting RNG Supply, Demand and Pricing

The RNG marketplace of key regions within North America is driven mainly by compliance programs that reward low carbon intensity fuel used for transportation markets. Project developers weigh project costs against profit potentials within both the traditional compliance market and emerging voluntary decarbonization markets. Project economics are in turn underpinned by location, feedstock types, midstream infrastructure and more.

The key drivers of current supply, demand and pricing are considered and analyzed below. For consumers of RNG in either compliance or voluntary markets, the imminent focus will be how to lock in long-term RNG supply earlier rather than later. Competition for supply could drive competing consuming entities to seek long-term supply agreements from producers. Speed is of the essence in building out the best and most impactful RNG projects. Gas utilities are seeking to decarbonize their supply chains, markets, and operations before other demand for RNG accesses the most economic supply.

5.1 Factors Affecting North American RNG Supply

Amid the energy transition, we anticipate RNG supply will grow as favorable project economics are underpinned by policy-driven supply and demand incentives. Investors seeking returns on their investment will certainly review RNG production and infrastructure projects as more voluntary and compliance buyers seek effective low-CI gaseous fuels. While supply potential forecasts by multiple entities have shown significant opportunity to expand RNG supplies, the output of most North American projects will seek the highest value markets. The markets with rules and methodologies that properly values RNG will define the highest priced markets. It will be those prices which must be met or exceeded by buyers in Ontario. Careful structure of Ontario policy and programs can draw supply of decarbonizing RNG, especially the most potent carbon negative kinds, which could enable Enbridge Gas RNG buyers to realize significant decarbonization at relatively manageable costs.

Sustainable RNG projects that earn risk-adjusted returns need market prices above production costs. With a sightline on favorable returns, sustained project investment in RNG can be expected. However, the energy transition is presenting a myriad of technological approaches and risk and return profiles that will compete for capital investment. The inventory of potential project sites must be diverse and large enough to capture attention amid the noise and disruption of the energy transition.

While there appear to be sufficient project opportunities and economics to scale RNG supply considerably, the productive output at each project is likely to become incrementally smaller. Many projects will need to be developed and operated to inject gas into the pipeline grid to sustain meaningful outputs through seasonal production and maintenance periods that are inherent with RNG infrastructure. The most productive plants with the lowest capital intensity will likely be developed well before the more numerous but smaller projects. From an RNG procurement standpoint, the utilities, or other buyers that act with urgency will likely find the lowest prices for RNG. That should be especially true for larger stable customers that can procure large volumes over the long term. Both term and volume will tend to attract RNG producers as they seek to lower pricing risks in the volatile transportation markets.

- **Project Development Appetite and Financing:** To grow RNG supply, more project investment is needed in North America. The appetite for investing capital in RNG projects will be furthered by sustainable margins that meet risk-adjusted returns. These in turn are underpinned by market prices that exceed production costs. With successful and sustained project investment, RNG can be expected to see supply expansion in North America. The inventory of potential project sites across the continent must also be diverse and large enough to capture attention among all the other opportunities for capital investment and returns amid the unfolding energy transition. While there appear to be sufficient project opportunities and economics to scale supply considerably, the productive output of each project is incrementally small. Many projects will need to be developed and operated. The least capital-intensive projects with high volume output will likely be developed before smaller or marginal projects.

- **Production Costs and Infrastructure Availability:** The cost of RNG production per unit of energy produced differs based on many factors. These include project size, upgrading requirements, maintenance, seasonality, distance to natural gas infrastructure, technology type, proximity of feedstock, quality of feedstock, and more. Capital costs estimated by capital market analysts for different types of RNG projects can range up to $228 USD per Dth/d of output from swine or dairy-sourced RNG projects, up to $190 USD per Dth/d for digesters at wastewater treatment plants (WWTPs), and between $35 and $40 USD per Dth/d for landfill gas-facilities. Utilizing $1.00 USD to $1.278 CAD and 1 MMBtu to 1.055056 GJ, we can convert the above four referenced costs to 276, 230, 42 and 48, respectively, all expressed in $CAD per GJ/d.

Table 5.1.1: Capital and Operating Cost Ranges (USD$)

	Output, Dth/d	**Capital Expenditure (Stifel), M$**	**Capital Expenditure (RBS) M$**	**Operating Expenditure (Stifel) M$/yr**
Dairy Farm AD	84	$7 or 228 $/Dth	$10 or 125 $/Dth	$0.2 or 6.50 $/Dth
Swine Farm AD	878	$50 or 156 $/Dth	Not available	$2.1 or 6.55 $/Dth
Wastewater AD	88	$6.1 or 189 $/Dth	$15 or 50 $/Dth	$0.1 or 3.11 $/Dth
Landfill	2,071	$27 or 35 $/Dth	$30 or 40 $/Dth	$4.0 or 5.29 $/Dth

Source: Anew Advisory presentation of estimates by Stifel Equity and RBC 2021 research

Costs could escalate if a project must cover an outsized share of interconnection cost or meet specialty processing and pipeline specifications. The resultant CI benefits of a given project's RNG would also be diluted if nearby pipeline injection points were not readily available. Project developers may avoid projects requiring significant investment in interconnecting pipelines or, alternately, in virtual pipeline solutions. Virtual pipeline solutions require investment and operating costs for compressors, liquefaction, loading racks and/or trucking logistics.

- **RNG Project Counts from Key Industry Associations:** The Canadian Biogas Association and its U.S. counterpart, the Renewable Natural Gas Coalition, both show strong historical and future RNG project growth. A considerable inventory of landfills has the potential to produce biogas. While many uses for landfill gas include local heat and power generation, the most likely near-term use for biogas that can be converted into RNG by processing is currently in the transportation market, which draws RNG to beneficial use and out of the flare systems and local energy pool at landfills. Furthermore, North America is a rich agricultural region that as a result has great biogenic agricultural waste potential. While population centers host both WWTP and separated food refuse generation opportunities, costs of developing projects based on these feedstocks will likely be limited. The SMART targets of Table 5.1.2. are from the RNG Coalition's action plan for waste sites in the US and Canada.[83]

- **Sustainable Methane Abatement & Recycling Timeline, The** SMART initiative that seeks to capture and control methane produced from the 43,000+ aggregated organic waste sites in the U.S. and Canadian portion of North America.

Table 5.1.2: RNG Project Counts

	Current Tally	SMART Target 2025	SMART Target 2030	SMART Target 2040
Operating	251	There is strong visibility on the 2025 SMART target of 500 operating projects given current tallies.	Reaching 1000 projects in operation would represent a CAGR of 14% in the 2nd half of this decade.	Reaching 5000 projects in operation by 2040 would represent a CAGR through the 2030's.
Under Construction	119			
Planned	138			
Total Sum	508			

Source: RNG Coalition data online and within Wastedive.com interview of Johannes Escudero

- **RNG Potential Assessments by Jurisdiction**: In their widely cited 2019 study[84] for the American Gas Foundation (AGF), consultants at ICF considered nine feedstock categories and 3 RNG producing technologies to create Low/High/Technically possible supply assessments of RNG potential within U.S. national and state jurisdictions for 2040. These tri-level assessments of potential future RNG projects are like the Proved/Possible/Probable resource assessments done for decades within the geologic natural gas industry. While one potential project may reflect production from waste resources and another starts with geologic resources, both approaches assess potential gas producibility given technology, operational and economic constraints. Of the nine RNG feedstock categories studied for AGF, the most prevalent in the marketplace today is RNG from landfills and manure projects. The three technologies assessed by the AGF study include anaerobic digestion, thermal gasification, and power to gas projects.

  Looking at those two classes of RNG in one jurisdiction (Michigan), we see that the Michigan forecasts for RNG from landfills published by ICF in their 2019 AGF study showed low, high, and technical resource potential estimates in 2040 of 25.2, 41.0, and 62.0 trillion Btu/y respectively (26.6, 43.3 and 65.41 PJ/y). By 2022, a study produced by ICF for the state of Michigan [85] showed potential estimates

[83] RNG Coalition SMART Initiative Plan to Utilize Methane Capture — The Coalition For Renewable Natural Gas
[84] https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf
[85]R https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Draft-Report---6-2022.pdf?rev=abfd113cf24c434d874a16bc187bae84&hash=EC2FF77C337D13929B262376B8618208

in 2040 for "Achievable", "Feasible", and "Inventory" RNG in 2050 at 31.5, 53.5 and 67.8 tBtu/yr (33.2, 56.4, and 71.5 PJ/y, respectively). The assessment showed a gain of as much as 30% in Michigan over the decade even though the earlier study in 2019 showed overall U.S. RNG assessments for landfill gas (LFG) RNG flat after 2035. Regarding RNG from manure projects, Michigan's 2050 technical resource potential as assessed in the 2022 study nearly tripled over the 2040 potential estimate 3 years earlier (rising to 39 tBtu or 41.1 PJ/y from 13.8 tBtu or 14.6 PJ/y).

We also note that the assessments by ICF did not consider avoided emissions for all RNG types. ICF set their assessments for RNG by keeping carbon intensity at zero. This simplified approach to pricing RNG is different than the rules of the California LCFS program and does not consider the profit motives of developers seeking to sell into the LCFS program. Instead, they simply recognized that biogenic RNG has zero carbon intensity.

Conversely, other similarly influential RNG resource assessment studies have been authored for Canadian jurisdictions (Torchlight Bioresources, 2020).

The Torchlight study determined feedstock conversion potentials for projects including anaerobic digestors and gasification technologies. But it characterizes the gasification technologies as "demonstration-scale" and "pre-commercial." Furthermore, "wood-to-gas" gasification technologies "should not be considered a significant contributor to RNG volume by 2030 and perhaps not by 2040." The Torchlight forecasts also do not include any commercialization of the power-to-gas technologies that may add RNG supply into the market.

Nonetheless, we offer herein a survey of supply potential from these non-commercial sources by reviewing studies pertaining to the broader North American and U.S. marketplaces. The RNG Coalition's North American data shows that from a 2017 base (242,000,000 ethanol gallon equivalent), the RNG used for North American transportation markets has grown at a compound growth rate of 24%[86]. If RNG supplies grow at that rate until 2030 from a 2021 base of 66.7 tBtu/y (70.4 PJ/yr)[87], then supply that year would average 454 tBtu/yr (479 Pj/y).

But we join with authors of the AGF and Torchlight studies in expecting forward RNG market growth overall to exceed the forward RNG growth in the transportation segment. From a 65 PJ/yr base estimated for the U.S. alone[88], we calculate that a compound annual growth rate of 29% would be required to meet the AGF report's forecast for U.S. Low Potential supply for 2030 at 689 PJ/yr. We note that this tally includes the AGF forecast for zero expected production of RNG from thermal gasification in 2030. The position to exclude thermal gasification for RNG supply prior to 2030 matches the position taken by the Torchlight authors. While AGF and Torchlight were of the opinion that thermal gasification produced sources of RNG may not be realized by 2030, it should be noted that two wood-based thermal gasification projects in Canada have been announced by REN Energy

[86]ttps://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/627027440ad1fc1e4922b215/1651517252292/NGV+RNG+Decarbonize+2022+5+02+22.pdf).

[87] We determined this baseline for 2021 by growing the 2020 operating RNG capacity of 59 million Dth/y as reported by NGV America in a study by Energy Vision and noted at https://ngvamerica.org/2020/12/22/new-assessment-shows-rapid-expansion-of-u-s-renewable-natural-gas-industry/ with the 2020 and 2021 transportation share of the market as reported by The RNG Coalition.

[88] About 6 Pj/y less than the N. Am total, as estimated for canada at https://biogasassociation.ca/resources/canadian_2020_biogas_market_report

International Corp in Ontario and British Columbia[89],[90]. The AGF study does show Low Case forecasts for power-to-gas RNG which we read as adding about 240 PJ/yr to North American supply if that forecast is realized. For comparison, the AFG High Potential case shows that a sustained growth rate of 40% through 2030 would be required from the current base to reach the study's 1,443 PJ/yr forecast for U.S. RNG output in 2030. The 2040 forecast production of advanced thermal gasification technology output in the US represents 8% of that High case forecast. The AGF High case also shows forecasts for power to gas technology in the U.S., and from those we see that they could add 30% more RNG supply on top of the conventional and advanced thermal gasification estimates for the year.

In addition to highlighting the quantity of RNG potentially available in Canada, the Torchlight study highlighted the importance of the quality of the RNG as well in that the study valued avoided emissions. From the study, we see that RNG supply from anaerobic digestion of non-crop biogenic feedstocks will be insufficient if avoided emissions are not recognized, captured, valued and utilized. The study quantified approximately 70 PJ/yr of “Feasible” waste-based non-crop conventional RNG resources in Canada. The study notes that “from a national energy policy perspective, 70 PJ/yr is only 0.6% of Canada’s current energy consumption. This limited volume means RNG will not be able to displace a large quantity of fossil fuels for GHG reductions.” Further, the authors state that while “the quantity of fossil fuels that can be displaced with conventional RNG is quite limited,” the analysis “determined that RNG can make an important contribution to decarbonization in Canada … Avoidance of methane emissions is likely to be the largest contributor of RNG to Canada’s climate strategy.”

The study estimated that conventional feedstocks could produce RNG with an average positive CI which, while 65% below geologic gas, the study concluded that “high on the list of priorities should be AD projects that utilize feedstocks with negative value and/or have a negative carbon intensity. These feedstocks include manure, urban organics, and biosolids. … the avoided methane emissions …should be recognized in the value of the RNG.” We note that BCUC-approved FortisBC’s RNG procurement programs have, as of 2021, led to a weighted average CI of –22 gCO_2e/MJ.[91] This was all the while complying with the BCUC $30/GJ RNG acquisition price cap. The cap was raised to $31/GJ for 2022 forward to further support RNG and reflect inflation.[92]

In conclusion, we believe RNG potential forecasts for North America do indicate strong supply potential for RNG in North America. The supplies of conventionally produced RNG from anaerobic digestion projects will likely lead supply through at least 2030 which is when the forecasters surveyed in this report expect material contributions by thermal gasification or power-to-gas technologies. Yet it is the recognition of both the carbon zero and unique carbon negative qualities of RNG, and not its rising quantities alone, that we expect will drive rapid and positive climate impact. The technology and feedstocks that will produce significant RNG volumes in the future are likely different than what some top-down models indicate. Therefore, we believe that a bottom-up approach that focuses on project counts and includes avoided emissions is more indicative of RNG supply growth.

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[89] A renewable natural gas plant is proposed for the District of Thunder Bay - SNNewsWatch.com

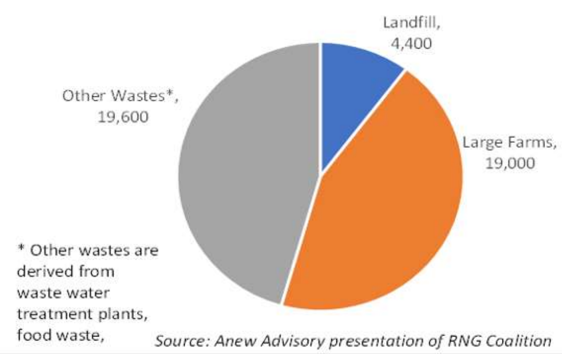
[90] A first for North America: FortisBC, REN Energy to produce RNG from wood waste - Canadian Biomass Magazine

[91] Page 47 of 266, FEI Stage 2 Revised RG Program BCUC IR1 Response (fortisbc.com)

[92] Figure 2-1 within DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf (bcuc.com)

- **RNG Coalition Potential Project Inventory**: The RNG Coalition counts nearly 47,000 waste facilities in North America that could be developed for RNG production. While North America hosts more landfills than that, roughly 4,400 sites are seen by the RNG Coalition as potential RNG production sites. At the early part of last decade, according to the RNG Coalition, nearly 100 % of all RNG produced was at landfill projects. Today, 70% of projects nearing startup are landfill gas sites. Of those in the early phases of construction, 45% are at landfill sites. These trends show that developers are diversifying capital investment into the Large Farm and Other Waste categories. These categories of RNG producing facilities are capable of capturing value from lower carbon intensities and avoided emissions.

Figure 5.1.1: North American Potential RNG Project Site Inventory



Source: Anew Advisory presentation of RNG Coalition

If 4,400 potential landfill projects were developed to yield 2,000 Dth/d each, they could produce 8.8 million Dth/d (9.28 PJ/d). For CI-sensitive programs like the North American LCFS programs, RNG that is injected and delivered with an average 45 gCO_2e/MJ CI (versus geologic gas at an estimated 70 gCO_2e/MJ) could fully decarbonize 3 million Dth/d (3.16 PJ/d) of LDC gas. We use 70 gCO_2e/MJ as a general unmitigated reference value since it ~~i~~s the average of the three reference values for unmitigated carbon intensity used within the BCUC LCFS[93], California LCFS[94], and Canada RFS[95] compliance transportation programs (63.64, 79.21, and 67.0, respectively, all values in gCO_2e/MJ).

If all farm digestors were developed to yield 350 Dth/d with a grid-injected CI of -350 gCO_2e/MJ, this 6.65 MM Dth/d (7 PJ/d) of farm RNG could decarbonize 40 million Dth/d (42.2 PJ/d) of grid gas use. If the "Other" RNG projects were developed to yield an average 100 Dth/d with an injected CI of 0 gCO_2e/MJ, then Other RNG could decarbonize the direct emissions of that same volume (1.96 Dth/d or 2.07 PJ/d) of consumed grid gas.

The North American project inventory could produce a combined potential 17.4 million Dth/d (18.4 PJ/d) which if under a CI program like the CA LCFS, could fully decarbonize the equivalent of 45.7 million Dth/d (48.2 PJ/d) of geologic gas in the grid. If that RNG was used in volumetric programs that count any RNG as simply carbon neutral (CI=0), then these projects could only decarbonize the direct emissions from the volume of geologic gas that they displace on a 1-to-1 basis. Current EIA data for the US and Canada peg natural gas consumption at 84 million Dth/d and 11.4 million Dth/d (88.6 and

[93] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/210526-fei-sec-71-shell-bpa-bcuc-ir1-response.pdf?sfvrsn=f9e6f53c_2

[94] See table 7-1, https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf

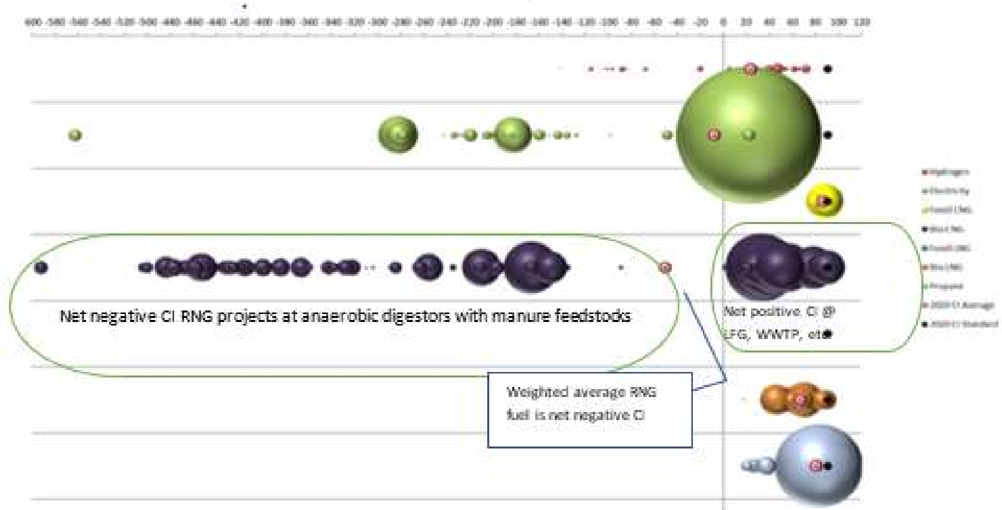
[95] https://www.gazette.gc.ca/rp-pr/p2/2022/2022-07-06/html/sor-dors140-eng.html

12.0 PJ/d) respectively. The entire inventory of RNG projects if developed as above could decarbonize nearly half (48%) of current North American grid gas consumption if negative CI's are considered or just 18% if RNG is only seen as carbon neutral.

- **RNG Supply Potentials vs Realism:** Converting biogas into RNG requires onsite or interconnected gas processing capacity. That capacity must extract impurities to yield a marketable RNG gas stream that meets pipeline quality specifications. RNG producing projects will also require pipeline injection points and/or virtual pipeline solutions to move RNG to market. The capital investment and operating costs for these projects can preclude or delay the development of disadvantaged locations and projects. From a standpoint of capital efficiency, the greatest RNG output for the lowest capital investment can likely be found at projects within existing landfills. In fact, some landfills have older biogas-to-power or heat applications. These can be supplanted by new energy transition technologies (i.e., solar) and yield opportunities to redevelop a producing landfill for RNG production.

  Landfill RNG volumes suffer from relatively high carbon intensities in comparison to other forms of RNG. Achievement of net zero performance is not possible with landfill RNG regardless of the mix, cost or volumes procured. Even if a well-funded customer sought to replace all geologic natural gas use with RNG from LFG projects, that customer would not achieve full decarbonization despite the high cost. Despite higher procurement costs, which would be multiples of conventional natural gas, the decarbonization would be only partial. More expense for limited decarbonization potential will likely not be a good formula for regulated utility buyers.

Figure 5.1.2: CI Scores Compared in California LCFS Markets



(Source: CARB 2021 Volume Weighted Averages, annotations by Anew Advisory)

Projects at WWTP can deliver carbon neutral RNG with certified CI scores of zero. That means a client buying WWTP RNG could theoretically achieve net zero performance if all geologic gas was replaced with RNG from WWTP projects. There are likely very few buyers who would seek this option and even fewer project developers that expect a big market populated by these kinds of buyers to develop. Dairy and swine farms are currently the one commercial RNG production option with both powerful decarbonization potentials and sizeable supply scale-up opportunities. In the California LCFS market, RNG gas from swine and dairy projects can be certified with CI pathways in as low as -600 g CO_2e/MJ.

Table 5.1.3: RNG Price and Performance Varies by Feedstock and Production Technology

	CI score CA-GREET, gCO_2e/MJ	Stacked EA Value, \$/Dth	Tonne CO_2e reduction/Dth	Decarbonization Impact Price, \$/tonne CO_2e
Landfill Gas	40	35.64	0.037	954
Food Waste AD	0	39.23	0.075	520
Dairy Manure AD	-175	54.90	0.242	227
Swine Manure AD	-375	72.81	0.433	168

Source: Anew representations for Argus prices dated 7/20/2022 per Jaffe et al method.

The combustion of one unit of highly potent carbon negative gas can effectively decarbonize the combustion of 7.5 times the volume of regular geologic gas. With such a powerful decarbonization tool, this RNG can be used at a 14% mix rate within geologic natural gas to achieve full decarbonization. This performance is not possible with LFG-derived RNG and it contrasts strongly against the 100% mix rate required for full decarbonization using RNG from WWTG or a more efficiently-produced version of landfill gas RNG with a zero CI. Superior decarbonization properties of swine and dairy gas in the CA LCFS market results from regulator recognition of the value of RNG's avoided emissions.

Despite swine and dairy manure higher prices on a per-energy unit basis, the price per tonne of CO_2e abated, a measure of its performance, is greatly lower than RNG from other LFG and WWTP opportunities. The superior performance translates into more credit generation potential within the LCFS and other CI-aware programs. More credit generation means more market value and financial return shared with the producer. Transportation customers commenting to FortisBC noted this reality, and the comments are summarized by FortisBC in their statement that customers buying RNG on the open market "pay more for RNG with lower carbon-intensity, (yet) the additional credits more than make up the difference."[96]

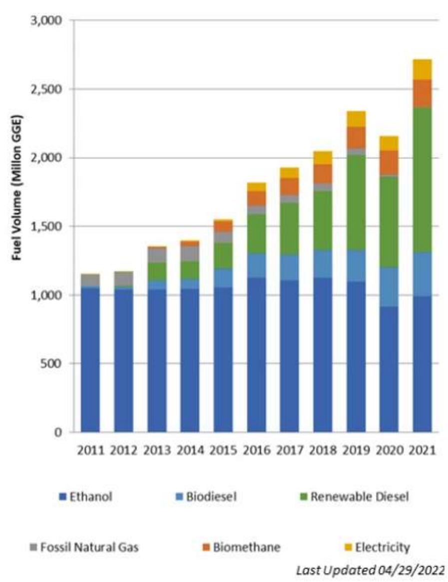
This explains why the average type of RNG used in the LCFS program of California is in the negative range. The unit price for the energy may be high, but that same unit of energy has a very valuable monetizable credit yield. It also has a very low cost and impactful decarbonization performance relative to other partial-decarbonization options with positive CI scores. As utilities seek deep decarbonization with low volume purchase requirements and goals to minimize consumer sticker price shock, RNG projects at swine and dairy farms will likely ramp supply to rise to the occasion.

[96] See pages 255 and 256 of 559, https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf

5.2 Factors Affecting North American RNG Demand

- **Demand in Transportation Compliance Markets:** Alternative fuel demand in California's LCFS marketplace shows the demand growth for RNG amid other competing transportation fuels. Over the last ten years, alternative fuel demand has more than doubled. In the early days of the LCFS program, ethanol and geologic natural gas were the fuel choice options. Demand has dwindled for both as bio and renewable diesel, biomethane, and electricity has taken share and driven demand higher in more recent years.

Figure 5.2.1: California LCFS Program Alternative Fuel Demand Growth



Source: California Air Resources Board

In Ontario and Canada, the same rotation toward higher percentages of RNG in gaseous fuel pools may play. The RNG Coalition commissioned work by Bates and White Economic Consultants showing gas demand in CNG and LNG propelled roadway transportation across North American rising from a base of 995 million gallons of gasoline equivalent (GGE) demand in 2021 to 1056 million GGE in 2025. That is a growth rate of 1.4% on average, compounded annually. The equivalent in dekatherms per day in 2025 is 368,542 Dth/d (0.385 PJ/d). That volume represents several multiples of current North American RNG supply. It is not guaranteed that the mix of transportation gas fuel will supplant geologic or fossil gas entirely, but the California experience may offer a touchstone if voluntary and compliance market programs in aggregate evolve similarly.

- **Demand in "Pre-Compliance" Transportation Markets:** Although its greenhouse gas emission regulations and standards are still evolving, the maritime sector can be seen as a significant "pre-compliance" decarbonization market. Liquefied natural gas, either sourced by geologic or biogenic supplies, is seen by ship builders, owners, and operators as a commercially available marine decarbonization fuel.

Decarbonization mandates are soon to be launched by the United Nation's International Maritime Organization (IMO) for larger maritime vessels operating in international waters. The IMO will in 2023 begin monitoring vessel operations for compliance with new ratings programs around carbon intensity. Other jurisdictions including the EU have additional pre-compliance initiatives underway for maritime traffic in their own jurisdictional waters. Compared to marine distillate fuel which is consumed globally in quantities nearing four million barrels per day or nearly 20 million Dth/d, the use of LNG in gas-fueled engines offers significant reductions in carbon intensity. The use of RNG can further reduce emissions to or below zero depending on RNG mix and the recognition of avoided emissions.

The LNG export industry has long used gas propulsion to move LNG carriers from exporting liquefaction terminals to importing regasification plants around the globe. In recent years, ship builders, owners and operators have adopted gas propulsion for many other classes of maritime vessels. With interests in exceeding the 20% relative decarbonization potential considered possible with LNG fuels, several firms have loaded RNG fuels into marine vessel fuel tanks in order to achieve lower or even zero carbon maritime operations.[97, 98]

Anew to date has completed two such RNG bunkering events in US markets. The latest occurred in Spring 2022 with the launch of a newly constructed Offshore Supply Vessel. Anew provided the bunker fuel supplier with an appropriate volume of swine-based RNG to create a carbon-neutral blend for the vessel's operations in US Gulf Coast waters.[99] RNG bunkering events have occurred elsewhere, especially in the European Union. There, gas-propelled cargo ships, ferries, and cruise liners have bunkered RNG to meet or exceed long-term compliance requirements and voluntary goals.[100]

Multiple other technologies exist for maritime decarbonization and rules are evolving. Yet the magnitude of this industry's potential gas demand and its existing use of RNG require monitoring for its potentially large demands for RNG.

- **Demand in Voluntary Markets:** The methane contained within gas produced and processed to pipeline quality standards is chemically identical to the methane sourced through geologic or other means. However, the release of CO_2 resulting from the combustion of biogenic methane is not seen as a contributor to anthropogenic climate warming. On top of those energy and environmental benefits, RNG projects can capture biogenic methane emissions that would have otherwise off gassed into the climate during the decay of biogenic materials. The ability of RNG projects to capture biogenic methane avoids deleterious methane emission leakage into the atmosphere.

  User groups therefore consider RNG as a drop in replacement fuel for natural gas whose use can reduce anthropogenic warming. It's flexibility and compatibility with existing infrastructure and uses positions RNG as a premium option to reduce CO_2 in the economy.

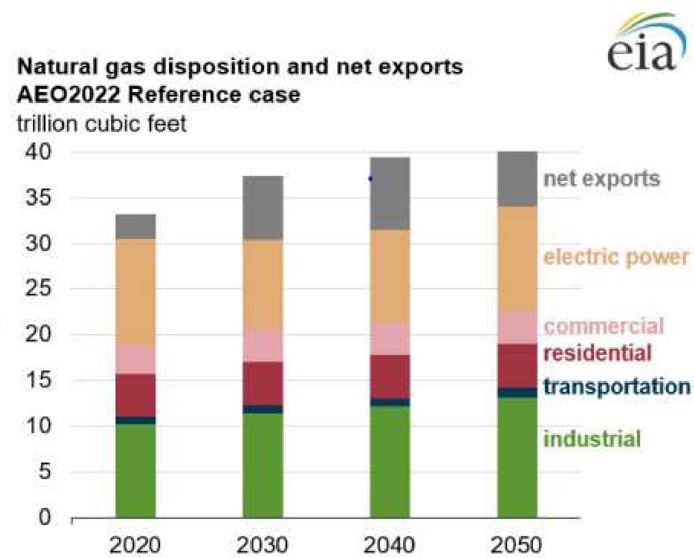
[97] https://pivotallng.com/pivotal-lng-providing-renewable-lng-to-worlds-first-carbon-neutral-platform-supply-vessel/
[98] https://pivotallng.com/jax-lng-and-tote-complete-first-renewable-lng-bunkering-in-the-united-states/
[99]
[100] https://www.biokraft.no/press-release-hurtigruten-partners-with-biokraft-in-record-breaking-biogas-deal/

Other decarbonization options exist today to serve in the energy transition. Fuel switching can be done for multiple end uses. Options include electrification, hydrogen and its potential carriers like ammonia and methanol. Efficiency improvements or demand destruction can also reduce energy use and concomitant carbon emissions.

Little visibility exists into which energy source will gain share, which will lose share, and what the overall market needs for energy will be. While less rigorous than other models, one approach for estimating RNG demand is to take current demand for natural gas as the potential market for RNG if it was available today. The RNG Coalition suggests that the ultimate market for RNG when amply supplied is none other than the then-current market for natural gas.

Utility programs that target all tiers of customer segments (industrial, power, commercial, residential) reflect this thinking inherently. Little end-use natural gas occurs outside of the confines of pipeline delivery. One exception to that rule is the currently non-material gas demand served by virtual pipeline operations (truck delivered CNG or LNG).

Figure 5.2.2: US Gas Demand Forecast by EIA, Annual Energy Outlook 2022 Reference Case



Source: US EIA

For the 2020's, the US EIA projects US aggregated natural gas demand will hold roughly flat with 2021 levels. On a disaggregated basis, the demands within the residential, commercial and power generation sectors fluctuate slightly to net out the noticeable gain in industrial natural gas demand. The EIA forecasts show significant increases in natural gas demand related to producing, pipelining, and compressing rising volumes of geologic gas to serve rising LNG exports that more than double during the decade.

The significant growth drivers in EIA's Annual Outlook forecasts for natural gas demand this decade are the 50% and 13% growth rates in lease + plant fuel in US gas producing fields and in gas consumed to liquefy LNG for export, respectively. Those gains from very small bases were diluted by lesser gains in residential, commercial, and roadway transportation segments. The positive one quadrillion BTU forecasted gain in the industrial space over the decade was offset by a nearly equal negative 1 quadrillion BTU in forecasted demand decline in the electric power sector. All told, US demand is forecast to enter the 2030 timeframe with a gas demand level essentially flat with that of 2021. The forecast shows a peak demand occurring in 2024 at 31,840 million Dth per year (33,631 PJ/y) before sagging modestly and again returning to that level in 2028 before going on a slow decline forward. On a daily basis, that peak rate during this decade represents approximately 87 million Dth/day (91.8 PJ/d).

- **Registry-Listed RNG Certificates and Trading:** Where compliance programs exist, jurisdictional regulators and administers specify how and where the mandated listing, trading, record keeping, and retirement of program credits occurs. The voluntary marketplace has no one registry specified or mandated for use. Third-party independent registries have arisen to serve the role for the voluntary marketplace In the North American RNG marketplace, the M-RETs registry became the place where certifications can be traded for the voluntary marketplace. M-RETs initially was founded to provide a platform for the voluntary registration and trading of Renewable Energy Credits (RECs) in the electric power industry. The broadening and extension of its platform and services into the RNG marketplace was launched on January 1, 2020.

Table 5.2.1: RTC Certificate Attributes Tracked in M-RETS

Account Level	Project Leve	RNG Attributes
Account Holder	Project Name	RTC Serial #
M-RETS ID	Location	Vintage
Account Number	Volume of RTC	Carbon Pathway
	Feedstock	CI Score
	Listed Quantity	Independent Verification

Source: Anew Advisory presentation of M-RETs information

The M-RETS Renewable Thermal Tracking System issues one RTC for each dekatherm of RNG. An RTC specifies details around the production and chain of custody, project level details, and environmental attributes. Importantly, this includes for each RTC include the CI resultant from scientifically validated carbon intensity pathways as developed using Canada's GHGenius model, Argonne National Labs GREET model, or the LCFS lifecycle pathway used by the California Air Resources Board.

When an RNG project is listed on M-RETs, the RTCs are meant to give transparency to buyers as well as those who have oversight of the buyers (e.g. - the utility commissions of regulated distribution utilities with program purchases of green gas). A key service available through M-RETs is an RTC trading platform that affords efficient digital transactions. Digital trading can aid liquidity and volume that ultimately tends to improve market function, price discovery, and growth in both RNG use and production.

Green-E is another pending certification and standard that is being developed by the Center for Resource Solutions. This standard will accept a limited number of pathways and has specific requirements and rules for listing and certification of RNG under the standard. This certification will likely apply to a subset of voluntary RNG types and classes. M-RETs is approved for use in tracking transactions within Canada and the US for Green-E certified RNG, according to current program materials.

- **Enbridge Gas RNG Demand Initiatives to date:** The pilot voluntary RNG purchasing program offered by Enbridge Gas in Ontario is roughly halfway through its 2-year pilot timeline. A more developed offering is available to the customers of Enbridge Gas's affiliated gas distribution utility, Gazifère.[101]

  Enbridge Gas as a corporation is also interested in decarbonizing a broader range of operational activities related to the energy transition.[102] As part of that ambition, the company has set upon goals to reach significant and sustained levels of green gas use to offer long term decarbonization options to customers of its Enbridge Gas distribution utility.

  The trend to direct RNG output to B.C. and other RNG markets that offer high value or long-term contracts will likely continue for the short and mid term. The RNG ambitions of a utility within a regulated service territory will face supply competition from across the continent for the foreseeable future. Gas utilities will likely need to procure RNG from producers wherever they are found on the continent under flexible book and claim delivery procedures that assure greatest logistical efficiency. Given the continental competition, long-term contracts covering large volumes will likely draw the best bids from producers across North America.

  An illustration of these realities can be seen in the procurement plan disclosures by FortisBC.[103] These plans show they procure RNG from projects in jurisdictions across Canada and the U.S., including from within Enbridge Gas's Ontario franchise area. Projects located in B.C. represent less than 30% of the approved procurement contracts, while projects in Ontario represent in excess of 42%.

5.3 Factors Affecting North American RNG Pricing

North American RNG prices are set by producers seeking the highest value market on the continent. Spot market prices are higher than long term contract purchases. On a long-term contract basis, costs are typically set closer to a producer's economics. RNG is processed to pipeline specifications and is capable of being injected and moved to any meter on the continent. As a result, the price is fairly uniform when sold on the short-term market except for transportation differentials. Most producers seeking to optimize return on their investments seek pathways to the high value markets created by the fuel standard regulations within State of California for short term sales of RNG. Book and claim mechanisms can allow RNG from any part of the continent to reach and participate in distant markets under multiple existing pathways that spell out delivered RNG carbon intensities and therefore credit value under fuel standard programs.

- **Drivers of Price Volatility~~:~~** In addition to the underlying volatility of the fossil transportation market (crude oil, gasoline, diesel, etc.), there are unique drivers specific to RNG that can affect its value. While natural gas is not yet a popular transportation fuel, its use in heating and power generation set up additional volatility and seasonality through the year. Furthermore, RNG is valued both for its

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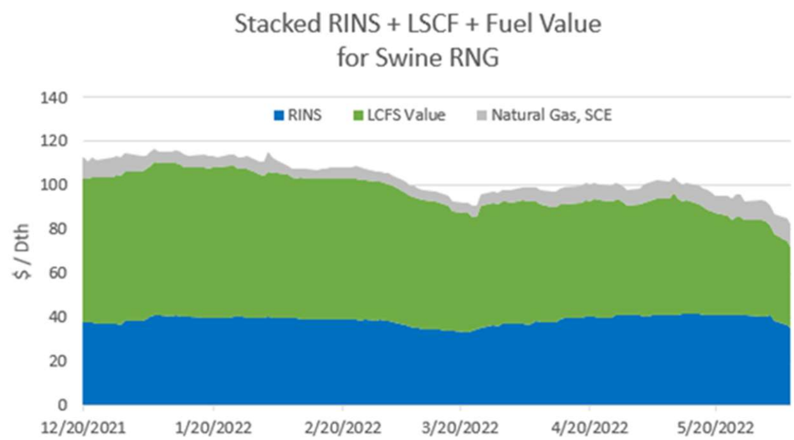
[101] See Renewable Natural Gas - Natural Gas, Heating, Furnace Gatineau - Gazifère (gazifere.com)
[102] https://www.enbridge.com/about-us/our-values/sustainability-goals
[103] Please see Table 6-1 in DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf (bcuc.com)

fuel value (in line with geologic natural gas) and for the compliance market value in relevant transportation markets. The most influential transportation markets are in the California Low Carbon Fuels Standard marketplace at the state level, and the U.S. Renewable Fuels Standard at the federal level. The value for RNG is calculated differently in each jurisdiction. Further, the use of RNG in California qualifies for RNG credits under both the state and federal programs. This is the concept of “stacking” or simply adding up the multi-jurisdictional credit values for a volume of RNG. To these credit values, the energy fuel value is added. The price for RNG thereby effectively rolls up the economic fundamentals and market price vicissitudes for natural gas, transportation fuels, state and federal decarbonization compliance programs. Therefore, there is significant volatility in spot RNG indicative values as built up from daily prices as show in the following figure.

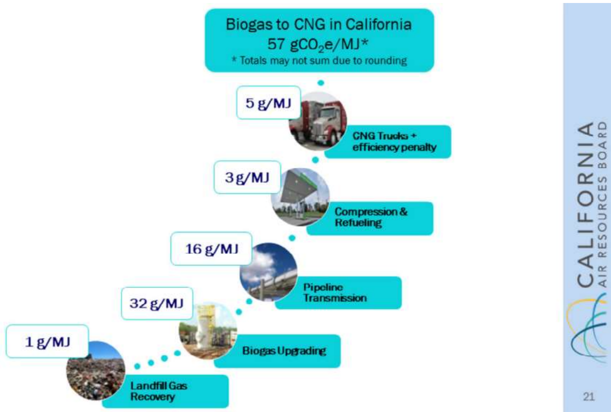
FIGURE 5.3.1: Price Volatility of RINS, LCFS and Natural Gas Fuel Values



Source: Anew Advisory representations of Argus 07/20/2022 price per Jaffe et al method

- **RNG Types by CI Score:**—Carbon Intensity of RNG is fundamentally driven by the RNG production process, starting with supply. Biogenic and cellulosic materials within land fills off-gas methane at vastly different rates than the organic solids in wastewater treatment plants or in the wet agricultural waste manure handling operations. As such, the supply and production of RNG is the largest contributor to RNG CI. All forms of biogenic methane must also be processed to remove sufficient non-methane constituents and contaminants to meet pipeline quality specifications. These contaminants can include mercury in landfills. More commonly, CO_2 is found along with methane because of organic matter decomposition and must be reduced via processing to pipeline specifications. The establishment of an RNG CI also includes adjustments for the CO_2 impact of transportation, distribution, and consumption.

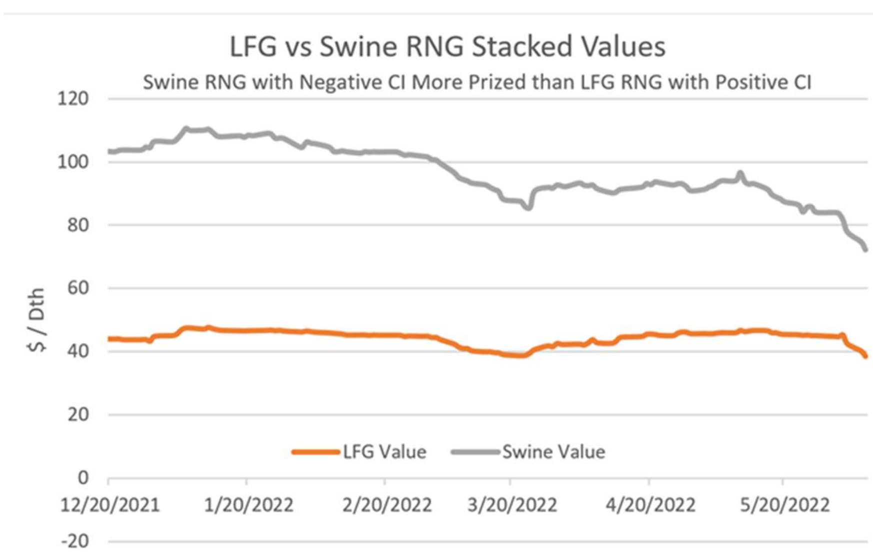
FIGURE 5.3.2: Building up CI Scores for Landfill Gas in California LCFS Markets



Source: California Air Resources Board

- **Impact of RNG CI on Prices:** The goal of LCFS programs across North America, including those in B.C. and California, is to reduce carbon in transportation by reducing the embodiment of CO_2 within each unit of delivered transportation fuel. CI is therefore measured in grams of embodied CO_2 equivalent per megajoule of contained and delivered energy. Credits are awarded for the utility of a given fuel to be supplied to the market with lower CI than a reference baseline fuel. The fuels with lower (or even more negative) certified CI's will generate more credits and more value. Carbon negative fuels like RNG from wet manure producing facilities are highly valuable in LCFS programs. Swine and Dairy derived RNG offers not only potency in reducing transportation CO_2 emissions, but also can do more at a lower cost per tonne of reduced carbon and with less fuel volume introduced into the fuel mix.

FIGURE 5.3.3: Carbon Intensity and Price Performance of RNG by Type



Source: Anew Advisory representations of Argus prices through 07/20/2022 per Jaffe et al method

- **The Primacy of the California LCFS to US RFS Markets:** Because the roadway transportation market is one of the most difficult to decarbonize, regulatory programs have installed relatively lavish incentives to pull renewable supply of ever-cleaner fuels into transportation markets. California has been on the forefront of this trend. The LCFS crediting program is well established, well regulated, and strongly incentivizes certified production and use of RNG. Included within the California LCFS program structure for RNG is the recognition of the beneficial nature of avoiding methane off-gassing from biogenic material decomposition. RNG producers with facilities that prevent the release of more methane are rewarded with lower or even negative CI scores that add value and pricing power. Conversely, the federal RPS and its RIN price value only the fact that the average type of cellulosic RNG has at least 60% reduction of carbon intensity versus its reference. Credits are granted to a fuel that passes the threshold. No extra credit is given under the RIN program for extra decarbonization potency beyond that threshold. As such, the highest value portion of stacked US RNG prices have typically been seen in CI driven markets like California. That in turn pulls more supply from producers of the most potent types of concentrated carbon negative RNG into the marketplace.

- **How RNG Prices Stack**: As previously noted, the concept of "stacking" is the act of adding up any simultaneous values that a molecule of RNG can realize. Fuel buyers within state jurisdictional transportation programs are also subject to federal fuel rules, so the compliance market price for RNG includes both state and federal clean fuel values. In California, RNG values are driven by the LCFS credit price and California's CI rating for the fuel as determined by approved and modeled pathways by feedstock and project type. In the US program, the RFS value is dependent on the value of the attached Renewable Identification Number or RIN credit that the program allows. On top of these values, RNG buyers also must pay the producer for the energy content of the fuel. Adding the three values (LCFS program, RIN value, and Fuel value) on a consistent unit basis yields the stacked value (refer to Figure 5.3.1). California's compliance-driven transportation fuels market is currently the highest value market in the US for RNG because it stacks fossil, federal and state value.

- **How Voluntary Buyers Must Bid for Supply:** In theory, because book and claim methods for delivery of natural gas and RNG exist across North America, producers of RNG can effectively reap gross California revenues from nearly anywhere. These prices are the stacked sum of RINs, LCFS, and fuel value less pipeline transportation charges. This means buyers of RNG in North America are effectively bidding against fuel retailers and roadway fuel consumers in transportation markets. The willingness to pay for RNG by a voluntary buyer must effectively be at or near the compliance -driven fuel prices in the transportation marketplace. Because of the multi-jurisdictional stacked fuel prices, a seller of RNG in Michigan, for example, has a target price close to the fuel and fuel credit prices realizable in California. The stacked RNG value in transportation compliance markets (fuel value plus the value for RINs and LCFS credits) is effectively the opportunity cost that a seller in Michigan would forego if a project's RNG output was instead purchased by a voluntary buyer in Michigan. Buyers outside of California LCFS transportation markets can and do structure supply agreements at lower than stacked transportation spot pricing with producers. The procurement agreements of FortisBC, all subject to a price maximum of CAD $31/GJ, show such success in contracting long-term supply from projects in three Canadian provinces and three U.S. states.[104] Producers seek to insulate their revenues and cash

[104] DOC_65216_B-11-FEI-Stage-2-Comprehensive-Review-Application-of-Revised-Renewable-Gas-Program.pdf (bcuc.com)

flows from volatility by structuring long term unit price and volume contractual agreements.[105] The levers to realize lower prices for voluntary and non-transportation buyers include committing to longer term, higher volume contracts. We also note that voluntary buyers can procure RNG from a broader supply pool. Broadening of the RNG supply pool can be achieved by sourcing RNG from projects with production pathways that do not qualify for the highest value uses in transportation compliance program. For example, the California LCFS program does not have a pathway for crediting of RNG made with poultry litter[106], so RINs value bundled with fossil fuel value is likely the pricing benchmark that voluntary buyers of this type of RNG can target. Niche producers of poultry-based RNG include Clean Energy Biofuels and Bioenergy Devco.[107]

[105] See Kinder Morgan Inc. corporate presentation of August 10, 2022. https://s24.q4cdn.com/126708163/files/doc_presentations/2022/08/August-2022_vF1_Including-NANR.pdf

[106] See CARB LCFS pathway table spreadsheet at https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities

[107] https://www.bioenergydevco.com/feedstocks/ and https://cleanbayrenewables.com/technology/

APPENDIX A: Utility RNG Programs Summary

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
SoCalGas & SDG&E	California	RNG	California requires Natural Gas Utilities to supply 12% of 2020 core gas demand with RNG by 2030. LDCs must procure RNG amounting to 8 MMT of organic waste diversion by 2025.	Voluntary	- As approved, Residential customers will be able to select a fixed dollar amount per month ($10, $25, or $50) for the purchase of renewable natural gas. - Commercial customers will be able to select a fixed dollar amount per month or select a percentage of their consumption for the purchase of renewable natural gas, up to 100%.	SoCalGas estimates that the RNG Tariff program will incur marketing costs of approximately $330,000 over the first 5 years. SDG&E estimates the marketing costs over the first 5 years to be approximately $200,000. The residential customer program has a minimum commitment of 1 year. The non-residential customer program has a minimum commitment of 2 years. SoCalGas estimates the RNG Tariff program will incur approximately $90,000 in program marketing costs during the first year of the program and approximately $60,000 annually thereafter SDG&E estimates the RNG Tariff program will incur approximately $40,000 in program marketing costs annually. RNG supply will come through contracts with marketers who carry a portfolio of RNG supplies or contracts directly with biogas producers/developers If there are any shortages in supply, the supply will be made up with surplus supply or with purchases in future months In 2021, 14 billion cubic feet of RNG was distributed via their pipeline system In 2020 SoCalGas had approximately 5.6 M residential customers and sold roughly 229M Mcf of NG

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Puget Sound Energy	Washington	RNG and Offsets	Washington requires gas utilities to offer, by tariff, voluntary RNG service for customers with participation limited by availability of supply. Customer charge for RNG cannot be more than 5% of the amount charged to retail customers for natural gas.	Voluntary	- PSE offers both RNG and offsets to customers - Customers can choose to replace part of their NG with RNG. RNG increments start at $5/month. - Customers can also choose to purchase 3rd party verified offsets. Offsets start at $3/month.	PSE's RNG is produced by Klickitat Public Utility District at the H.W. Hill Renewable Natural Gas facility in Roosevelt, Washington. More than 1200 customers have enrolled since December 2021. In 2020 PSE had approximately 792,000 customers and sold roughly 59M Mcf of NG Participating customer revenue will be used to fund the ongoing costs of RNG purchases, administration, marketing, and overhead. RNG accounts for 0.5% of PSE's annual RNG program, and will potentially reach 3.5% by 2024

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Dominion Energy	Utah	RNG and Offsets	Voluntary	Voluntary	- Dominion offers two voluntary programs in Utah and Idaho called CarbonRight and GreenTherm. As part of GreenTherm customers can choose to add a number of RNG blocks that represent RNG green attributes to their monthly bill - Each block is $5 per month which is equivalent to 0.5 dekatherms, and customers can chose to buy as many blocks as they wish. -The CarbonRight program began in March 2022 and allows customers to choose to add $5 blocks a month to offset a typical home's emissions from natural gas, or business footprint. The program is open to residential, business or government. Each block is equal to 0.3533 mt CO2e which would equate to	GreenTherm: In 2020 a total of 10,518 blocks were sold and the associated marketing costs were $4,774, for a total program expense to admin ratio of 19% The total customer count was 1,165 for the RNG program. In 2021, 38,297 blocks were sold, the total administration costs were $8,078 for a total program expense to admin ration of 4% -The GreenTherm program seeks to purchase RNG environmental attributes from local sources; however, if Dominion is unable to find RNG from local sources, they will be purchased where available. -The funds from the blocks would go to 1) purchase of RNG, 2) administration of program, 3) any leftover will fund qualifying initiatives. The company estimated it would incur $265,000 in administration costs for the initial set up of the program, and $300,000 in the following year. -RNG would be procured through RFPs to vendors, producers, and suppliers to get the most favorable pricing CarbonRight:-The CarbonRight program currently uses two landfill gas capture/combustion offset programs it uses (one in Utah and one in Missouri), and a forest carbon project in Minnesota. These landfill offsets projects are registered under the Climate Action Reserve, and the forest carbon project is registered under the American Carbon Registry. -As a condition of the approval of the program, Dominion needs to maintain information about the selected offset programs on its website

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
					approximately 80 dekatherms of natural gas per year if one block was purchased per month for 12 months. -To obtain the offset projects, and RFP was sent out to select a portfolio of projects for the program to get known projects and costs	-Non-program participants will not bear any of the cost of the program. All costs associated with the project application were redacted from the file In 2020, Dominion had approximately 371K residential customers and has sold 12M Mcf of natural gas

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
DTE Energy	Michigan	RNG and Offsets	Voluntary	Voluntary	- CleanVision Natural Gas Balance program uses a mix of 95% carbon offsets and 5% RNG to allow customers to offset a portion or all of the emissions associated with their monthly natural gas use in the following amounts and costs: 25% ($4); 50% ($8); 75% ($12); 100% ($16)	Approximately 2800 customers opted into DTE's RNG program in first 6 months after its 2021 launch. By 9 months later, the customer count was 5000, and 12 months later was at 6500. In DTE's latest update in June 2022, they mention that the RNG program enrollment has reached 6,500 customers. In 2020 DTE had approximately 1.1 M residential customers and sold roughly 98 M Mcf of residential gas. More than 5,000 DTE Gas residential and small business customers enrolled in the program As a part of their next steps, DTE will start a companion program for commercial and industrial customers

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Nicor Gas	Illinois	RNG and Offsets	Voluntary	Voluntary	- Nicor Gas filed a rate request with the Illinois Commerce Commission, which includes a proposal to offer customers a new pilot program called TotalGreen. - Offers customers voluntary program to offset consumption with 5-20% RNG and remaining as carbon offsets or 0.5% RNG and 99.5% carbon offsets to test consumer price preferences. -There will be no physical delivery of RNG, but the environmental attributes will be purchased until such time that the market develops further and physical delivery can be achieved -Currently the program is being offered at cost, with no markups, and only participating customers will bear the	In 2020 Nicor Gas had 1.9M residential customers and sold approximately 195 M Mcf of residential gas. They currently have an RNG interconnection service pilot program for provision of an interconnection service between a renewable gas production facility and existing Nicor gas transmission or distribution facilities. Nicor investment for this program is limited to in aggregate up to $16 M, with each renewable gas production facility limited to $3.2 M. Nicor will negotiate for a set number of environmental attributes to be transferred from the developer to the pipeline owner, and use these attributes to offset GHG emissions associated with its broader portfolio. For the Total Green Program, criticism has been around not enough information regarding transparency with respect to the source, type of project, additionality of offsets and RNG credits and ongoing accountability to ensure offsets and RNG sources have a tangible connection to Nicor's system and local resources. There was also criticism that the program asserts it would result in a net-zero carbon footprint for natural gas usage but customers only purchase RNG and offsets equivalent to their on-site and end-use consumption, without accounting for upstream emissions. Nicor will not estimate and integrate upstream emissions in the program, and agreed to disclose in program materials that this program was only addressing a consumers GHG emissions and does not include lifecycle emissions that occur upstream. Interveners felt it was important to let the customers

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
					cost. There is no risk to consumers. -Much of the filing in docket P2021-0098 was considered confidential information and not given publicly.	know where the offsets were being purchased from, and what the project was so they are understanding what they are purchasing. It was indicated that projects should be in proximity to Nicor gas service territory when selecting offset projects.

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Summit Utilities	Maine	RNG	Maine requires the PUC to allow utility to use RNG for no more than 2% of the gas it supplies to its customers starting in 2022 and to allow a utility to use an additional 2% annually thereafter. Utility may include the costs of RNG in its cost-of-gas adjustment rate.	Voluntary	- Customers enrolling in Summit's program may elect to match 10 to 100 percent of the average annual usage of similar customers with RNG attributes. The quantity of RNG attributes, and a flat rate monthly fee, will be added and shown on enrolled customers' bills.	

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Vermont Gas Systems	Vermont	RNG and Offsets	Voluntary	Voluntary	- VGS offers customers two options for purchasing renewable attributes of RNG. Locally Sourced RNG specifically supports local supplies of RNG by acquiring the renewable attributes from Vermont projects, like the Goodrich Farm in Addison County. Blended RNG supports supply from all of VGS's RNG sources at a lower price per 100 cubic feet (CCF). -RNG supply is fixed price, term contracts, keeping costs relatively stable over time	- Currently, the Blended RNG Adder is $1.1436 per CCF and the Locally Sourced RNG Adder is $1.5098 per CCF This is the same for both residential and commercial customers. -In the event there is inadequate supply of RNG, the Company may meet the customer's RNG option by purchasing equivalent carbon offsets. If carbon offsets are not available, the Company will contribute equivalent revenue to the Clean Energy Development Fund. If this circumstance persists for longer than 30 days, the Company will notify all RNG Adder customers. -Vermont Gas intends to supply 20% of its supply mix for retail customers with RNG by 2030. The company proposed to add approximately 2% RNG per year into its portfolio. -the initial program proposal suggested a 12 month true up window that will allow RNG oversupply to be sold to customers if necessary and any undersupply to be met through additional RNG supply contracts or other means -VGS is looking at a way they can separate the attribute from the molecule such that they can bank the attribute, match them with sales, and spread out rate impacts over time -for any excess RNG not sold under the program, Vermont Gas may market the carbon offsets or any of the available credits relating to RNG and any revenues generated will be used to offset RNG costs. Vermont Gas will seek incentives such as the RFS RINS -RNG pricing took into account the carbon pricing at $100/ton

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
						-The average level for residential customers in the program is 40%, - since beginning to offer the program approximately 105,000 mcf of natural gas have been displaced. Anticipating in 2021 another 120,000 mcf/year -this includes voluntary annual usage of 40,000 mcf/year, the firm portfolio carrying 65,000 mcf/year, and Vermont Gas using 105,000 mcf/year for internal use.

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Avista - Idaho/Washington	Idaho, Washington	RNG	Washington requires gas utilities to offer, by tariff, voluntary RNG service for customers with participation limited by availability of supply. Customer charge for RNG cannot be more than 5% of amount charged to retail customers for natural gas.	Voluntary	The company will offer customers the ability to purchase blocks of RNG at a price of $5 per block of RNG environmental attributes, equivalent to 1.5 therms of RNG	Customers can start or stop this program at any time but it is subject to supplies lasting The costs will be covered by program participants and contained within the RNG program, with costs tracked separately. The company will use M-RETS to track the environmental attribute The RNG is being acquired from Puget Sound Energy
Fortis BC	British Colombia	RNG	The CleanBC plan calls for a minimum of 15% of natural gas be provided from renewable sources by 2030.	Hybrid	- Fortis BC allows natural gas customers to designate 5, 10, 25, 50, 100 percent of their natural gas use as RNG. - Fortis is seeking to modify its existing program, and expects all customers to receive a one percent RNG blend starting in 2024, and will increase over time to meet provincial clean energy targets -in the proposed program, all new	Fortis obtains their RNG supply from a range of suppliers such as farms, landfills, and wastewater treatment plants In 2019, the RNG demand exceeded the RNG supply and resulted in Fortis putting a temporary pause on the program. At this time there were 10,000 customer subscribed to the program The program was reopened in 2021 and still had continuing demand as there were approximately 350 customers on the waitlist At the start of the program the customer education and awareness expenditures were expected to be in the range of $300K per annum, after reopening the program with increased demand the expenditures are expected to be in the range of $340K per annum Fortis is aiming to have a RNG supply of 3.9M GJ in

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
					residential connections will be serviced with 100% RNG and they will continue to offer a voluntary program for existing sales customers	2022 Customers will pay a rate of $13.808/GJ for the RNG or $14.568/dekatherm
Energir	Quebec	RNG	In Québec, regulations require that the portion of renewable natural gas distributed in the gas system be 5% by 2025. This portion may be increased to 10% by 2030.	Hybrid	- Energir allows customers to convert up to 10, 30, or 100 percent of their natural gas to RNG for a cost of approximately $4.50, $13.50, or $45.50 respectively.	

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Gazifère	Quebec	RNG	In Québec, regulations require that the proportion of renewable natural gas distributed in the gas system be 5% by 2025. This proportion may be increased to 10% by 2030.	Voluntary	- Gazifère has a program to allow customers to add RNG consumption to their NG - Customers can choose their consumption percentage: 1%, 5%, 10%, or 100% - RNG rate: 54.50 cents/m3	RNG supply to a customer is only authorized if it is operationally feasible for the distributor to supply the customer with RNG over the course of a year If it is not operationally feasible, the customer will be placed on a waiting list. In 2022, 1% of the natural gas that Gazifère distributes is RNG They are aiming to have 5% RNG in their natural gas supply by 2025.
Southwest Gas Corp -Arizona	Arizona	RNG	Mandatory	Mandatory	1% of sales would be RNG by 2025, 2% by 2030 and 3% by 2025.	Southwest has had successful programs in Nevada and California. This program was rejected in 2020 because it was felt the environmental attributes of RNG couldn't be certified at that time, nor monetized. It was also rejected because it was felt the market was not fully developed enough for RNG for any cost certainties, and that the cost of RNG was too great compared to conventional NG. A workshop was to be conducted in 2020 to explore the role of RNG in Arizona.

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Black Hills Gas	Currently seeking approval in Colorado, but will soon submit applications with similar programs in Kansas, Nebraska, Arizona, Iowa, and Wyoming by 2023.	RNG and Offsets	Voluntary	Voluntary	The program provides residential or small commercial sales customers the option to purchase blocks which equate to approximately 25% (20.5 therms) of the average residential customer each, up to 100% of their use. For each block the company will procure RNG environmental attributes and carbon offsets, currently estimated at $5.00 USD per block. The product offsets 99% of CO2 emissions through carbon offset credits and 1% of CO2 through RNG environmental attributes. The program will be funded by participants only, and not passed on to non-customers. Blackhills has 180,000 residential customers, 15,000 small commercial customers. by the end of the pilot,	The pilot program is proposed to start Jan 2023, for 4 years, with plans to evaluate on a yearly basis. Fees will be used to cover environmental attributes, ongoing administration, marketing, and overhead costs. Total marketing costs range from $87,500 to $119,750 per year. Administration costs were estimated at approximately $50,000 per year, and IT expenses at $4500 per year. -the company has allocated $15,000 per year for compliance, environmental attribute and carbon offset credit verification and certification, and annual program audits The company is asking for a differed accounting mechanism to give the company an opportunity to defer expense in the year incurred, with the opportunity to recover those deferred costs in the future as program participation increases. In the early years of the pilot the anticipated expenses associated with upfront marketing costs in acquiring new participants are greater than the anticipated revenues due to low initial participation, resulting in expenses exceeding revenue. In subsequent years, increased enrollees could generate revenue in excess of program expenses, creating a regulatory liability. If the program becomes over-collected, the company will use the excess revenues to benefit program participants -by either acquiring more RNG and/or higher premium carbon offsets which would increase the CO2 emissions offset with each block enrolled. -All program costs will be accounted for separately from conventional gas supply including commodity and upstream costs -since RNG is not being offered as

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
					the company anticipates approximately 2900 participants. -Local RNG projects will be sourced to the extent possible -estimated cost through the pilot is $22/MMBtu for RNG, and will be transferred through the M-RETs system, and using the Green-E renewable fuel standard as possible	part of its supply mix, the RNG program costs will be accounted for separately. -the company expects to break even by 2027 once the pilot is complete, and due to consecutive under recoveries from 2023-2026, the cumulative program costs become fully recovered by 2031. -program budget also accounts for a 3rd party audit each year -the program is proactively anticipated the needs of the Senate Bill 21-264 Clean Heat bill that require gas distribution utilities to achieve a 4% reduction in GHG emissions compared to a 2015 baseline by 2025, and a 22% reduction by 2030, of which 1% and 5% of these reductions in 2025 and 2030 respectively can be from recovered methane

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Consumer Energy	Michigan	Offsets	Voluntary	Voluntary	-Participants can offset from 10-100% of the carbon emitted from natural gas consumption -open to residential and commercial businesses -offsets are focused on Michigan forests, but not limited to this	This program has not yet been approved.
NW Natural	Oregon	Offsets	Oregon Gov. Kate Brown recently signed SB 98 into law. The bill sets voluntary renewable natural gas (RNG) goals for the state's natural gas utilities, creating a path for RNG to become an increasing part of Oregon's energy supply.	Voluntary	- Residential customers choose either the Average Home option for $5.50 a month or the Climate Neutral option for about 10.5 cents more per therm used each month. - Business customer enrollment options start at $10.00 a month.	- NW Natural has signed agreements with options to purchase or develop RNG totaling about 3% of their current Oregon supply

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Columbia Gas	Maryland	RNG and Offsets	Voluntary	Voluntary	Columbia Gas is proposing a five-year RNG pilot - the Green Path Rider. Under the voluntary program CGM will purchase RNG, environmental attributes and carbon. Will match the customer's election of either a 100% reduction or a 50% reduction in emissions. Customers opting into the Green Path Rider will be charged an additional fee per therm that reflects the cost of the RNG environmental attributes and carbon offsets. The program would be offered to all residential and general service customers that are not in arrears.	

Utility Name	Jurisdiction	Program Type	Mandate or Voluntary	Participation	Type of Program	Additional Details
Liberty Utilities	Massachusetts	RNG	Voluntary	Voluntary	Liberty Gas will offer customers a program where they can choose between 25%, 50%, 75% and 100% of RNG for their gas use.	Liberties Gas has approximately 60,000 customers in Massachusetts -the company has a 20 year contract with an RNG facility at the Fall River Landfill, and Liberty has the exclusive right to purchase from the facility, and the facility will be obligated to sell and delivery exclusively to the Liberty the annual minimum/maximum volumes ranging from 84,458 dekatherms to 196,796 dekatherms per year up to a maximum supply of 168,917 dekatherms to 281,137 dekatherms . -the RNG is being delivered at a fixed cost of $9.25 per dekatherm, increased by 2% annually, to a final price of $13.48 per dekatherm. -in the event customers do not purchase RNG in sufficient volumes to utilize the amount required under the RNG contract, the company would use the RNG it has procured to provide gas service to its customers. -customers would enroll in the program for a 1 year commitment period -during the first two years of supply, the company has the option to purchase all the environmental attributes for the duration of the term for a fixed cost of $25/MMBTU. -this program was filed in March 2022, and has not been approved yet

APPENDIX B: Anew Qualifications

Anew Advisory Services, LLC is part of Anew, LLC which was formed by the recent merger of Element Markets and Bluesource under the ownership of the TPG Rise fund. The merger was driven by the realization of the complementarity between the deep expertise of the two companies. Anew has a combined 30+ years of experience developing more than 350 projects across 20 project types across all of North America, which to date, have yielded 180 million tonnes of verified greenhouse gas emissions addressed. Our mission is to make the highest and best use of the skills, capabilities, experiences and influence we possess to enable the greatest positive impact on climate. Our values of integrity, trust, creativity, and hope anchor our leadership position in both compliance and voluntary environmental markets, and as a key partner to clients pursuing scalable decarbonization strategies.

Anew's Renewable Natural Gas Expertise:

We leverage a dominant market position in ultra-low CI RNG, regulatory expertise, and relationships with marquee clients in the utility and transportation fuel sectors. Our Renewable Natural Gas team partners with farmers, landfill operators and wastewater treatment plants to generate renewable fuel, register it, and bring it to the market for utilities, fleet operators and voluntary buyers seeking to capture the benefits of cleaner energy. Anew is the largest volume independent marketer of RNG in North America. The amounts of RNG transacted by Anew have displaced 240,000,000 diesel gallons equivalent. Anew is active on the regulatory side as well as in operations and marketing. Anew has developed more than 35 active RFS or LCFS pathways for alternative transportation fuels. Additionally, Anew has been instrumental in leading Green-e to form new Thermal REC standard for RNG. Our in-house marketing services provide registration, credit generation, program compliance and sales of RINs and LCFS credits across a portfolio of demand side buyers. Along with providing long-term offtake agreements for large scale producers of RNG, Anew has become the recognized leader in bringing into the market highly potent ultra-low carbon intensity ("CI") RNG fuels.

Anew's Combined Approaches to Full Scope Emissions:

Anew has served compliance and voluntary users with renewable natural gas to offer a direct path to Scope 1 reductions by switching to RNG from natural gas consumption. Anew has also begun offering RNG paired with carbon offsets under its innovative Renew(TM) offering to create a carbon neutral footprint for natural gas use. The turnkey features of the Renew offering include the design of an off-the-shelf product that relieves decision paralysis. Renew is affordable and customizable in that a customer can change the blend rate of products to flexibly match specific climate goals and customer budget realities. The product is certified and leverages trusted 3rd parties to track and certify commodities while also easing administrative burden. Provides direct path to Scope 1 reductions. Anew currently has an inventory of over two million dekatherms of RNG listed on MRETS to support Renew demand.

Anew's Hydrogen Capabilities:

Anew's proprietary hydrogen business model combines solar power, RNG, and on-site steam methane reformation to produce and dispense clean hydrogen, while preserving optionality to move to electrolysis. Our experience is based on building Hydrogen Refueling Infrastructure (HRI) pathways in the rapidly expanding California hydrogen market. We are actively engaging with fleet owners and OEMs to develop hydrogen consuming solutions to meet their off-road and on-road needs and simultaneously helping our utility customers to explore and develop innovative strategies to participate and propel the hydrogen economy.

UNACCOUNTED FOR GAS (UFG)

RACHEL GOODREAU, MANAGER REVENUE AND COST OF GAS

1. The purpose of this evidence is to request OEB approval of a 3-year simple average methodology for forecasting unaccounted for gas (UFG) volumes beginning in the 2024 Test Year. This evidence presents historical and forecast information relating to UFG volumes and cost.

2. The evidence also addresses the following directives from and commitments to the OEB from previous regulatory applications:
   a) Provide a progress report on the implementation of the UFG Report's recommendations to address UFG[1];
   b) Present a proposal for consistent forecasting and management of UFG across the full franchise area[2];
   c) Provide reporting of UFG results, segregated by rate zone and activity (distribution, transmission, storage), with such recent historical information as is available as part of the rebasing filing[3]; and
   d) Address the impact of increasing the storage pool pressure gradient on UFG[4].

3. In this evidence, Enbridge Gas has defined UFG to describe the loss of gas from distribution, transmission, and storage. Historically, the following terms have been used to describe the various types of losses of gas:
   a) Lost and Unaccounted for Gas (LUF) – used in reference to storage losses in the EGD rate zone;

[1] EB-2019-0194, Decision and Order, May 14, 2020.
[2] Ibid.
[3] Ibid.
[4] EB-2020-0256, Decision and Order, April 22, 2021.

b) Unaccounted for Gas (UAF) – used in reference to distribution losses in the EGD rate zone; and
c) Unaccounted for Gas (UFG) – used in reference to distribution, transmission and storage losses in the Union rate zones.

4. This evidence is organized as follows:
   1. Current Forecast Methodology
   2. Proposed Harmonized Forecast Methodology
   3. Historical and Forecast Information Relating to UFG Volumes and Cost
   4. Directives and Commitments from Previous Regulatory Applications

<u>1. Current Forecast Methodology</u>

5. The UFG volume forecast prior to rebasing in 2024 is underpinned by three OEB-approved forecasting methodologies. These methodologies are specific to each rate zone.

6. In the EGD rate zone, there are two methods for forecasting UFG volumes. The method to forecast UFG volumes relating to distribution operations is based on a single equation regression model that estimates the relationship between historical UFG and the total historical unlocked customers[5]. Unlocked customers are used as an independent variable with the presumption that the amount of UFG is correlated to the size of the distribution system. The forecast of UFG volumes relating to storage operations was determined in EGD's 2007 Rate proceeding EB-2006-0034[6] and has been used since then. A portion of the UFG volumes is allocated to

[5] EB-2011-0354, Exhibit D3, Tab 4, Schedule 1; EB-2014-0276, Exhibit D1, Tab 2, Schedule 3.
[6] EB-2006-0034, Exhibit D1, Tab 4, Schedule 1, p.14.

unregulated storage operations. The allocation to unregulated storage operations was updated in the 2016 Rate Application[7].

7. In the Union rate zones, the UFG forecast is based on the 3-year weighted average of the ratio of UFG volumes to total system throughput. The ratio of UFG volumes to total system throughput is weighted, where the most recent year has a 3/6th weighting, the second most recent year has a 2/6 weighting, and the third most recent year has a 1/6 weighting. The 3-year weighted average ratio is then multiplied by the throughput forecast to derive the forecast of UFG volumes. Based on the OEB-approved forecasting methodology, the ratio of UFG volumes to total system throughput used to forecast UFG volumes for the period of 2013 to 2023 is 0.219%, as approved in Union's 2013 Cost of Service Application[8].

8. For all three forecast methodologies, the OEB-approved reference price is applied to the UFG volume forecast to derive the UFG cost. The current OEB-approved reference prices and the proposed harmonized reference price are provided at Exhibit 4, Tab 2, Schedule 2.

2. Proposed Harmonized Forecast Methodology

9. Enbridge Gas proposes to determine the forecast for UFG based on a 3-year simple average of actual UFG volumes. This proposal was selected based on an evaluation of the 3-year weighted average of throughput ratio and single equation regression methodologies currently used by Enbridge Gas as well as two other forecasting methodologies commonly used by peers in the industry, specifically the

[7] EB-2015-0114, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, December 1, 2015, pp.14-15.
[8] EB-2011-0210, Exhibit D3, Tab 2, Schedule 2, Updated; EB-2011-0210, OEB Decision and Order, October 24, 2012.

3-year simple average of actual UFG volumes and the 5-year simple average of actual UFG volumes.

10. Enbridge Gas compiled its own summary of UFG forecasting practices based on information collected through the American Gas Association (AGA), the Canadian Gas Association (CGA), and a search through publicly available filings of other utilities in North America. Table 1 summarizes the findings of this data collection and illustrates that six utilities were found that currently use the 3-year simple average of actual UFG volumes forecasting methodology, five utilities were found to use the 5-year simple average of actual UFG volumes forecasting methodology, and five utilities were found that use other forecasting methodologies. The 3-year and 5-year simple average of actual UFG volumes forecast methodologies are the predominant approaches amongst the utilities for which data was collected.

Table 1
Summary of UFG Forecasting Methodologies Among Canadian and American Utilities

Line No.	Company	Jurisdiction	3-year Average	5-year Average	10-year Average	Other Methodology
			(a)	(b)	(c)	(d)
1	Company A	Alberta	Y			
2	Company B	Michigan		Y		
3	Company C	Michigan		Y		
4	Company D	Indiana			Y	
5	Company E	New York				Y
6	Company F	Ohio				Y
7	Company G	Pennsylvania				Y
8	Company H	Pennsylvania	Y			
9	Company I	Wisconsin	Y			
10	Company J	Multiple States	Y			
11	Company K	Connecticut		Y		
12	Company L	Illinois				Y
13	Company M	Multiple States		Y		
14	Company N	Unknown		Y		
15	Company O	Unknown	Y			
16	Company P	Unknown	Y			

11. The 3-year average and 5-year average of actual UFG volumes forecast methodologies were selected to be compared with the forecast accuracies of the current methodologies used by Enbridge Gas, for the period of 2017 to 2021. Accuracy is assessed by the difference between forecast and actual UFG. Accuracy was used to evaluate the various methodologies because the Company's current and proposed unaccounted for gas variance accounts are measured as the variance between actual and forecast levels. According to this criterion, the best forecasting methodology provides the smallest deviation between actual and forecast and the direction of the deviation is neutral to all stakeholders.

12. Prior to completing the accuracy comparison of the selected methodologies, the regression used for the EGD rate zone was estimated using Enbridge Gas actual UFG data from 2008 to 2021, using historical UAF volumes from the EGD rate zone and historical UFG volumes for the Union rate zone[9]. Based on the results of the regression analysis, it was determined that the regression methodology was not an appropriate method to use to forecast UFG, when using combined historical UAF and UFG volumes. Therefore, the EGD rate zone regression methodology was eliminated from the further analysis, including the accuracy comparison

13. Statistical model accuracy measures, including out-of-sample mean absolute error (MAE) and mean absolute percent error (MAPE), were used to evaluate the forecasting accuracy of the remaining methodologies[10]. The MAE is the average of yearly absolute errors, where the absolute error in any year is the absolute difference between the actual and forecast value. MAPE is the average of the

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[9] The current EGD regression equation includes a dummy variable to account for the anomaly in 2004, where UAF volumes were negative. This dummy variable was excluded from the model for the purposes of this analysis, as the combined historical volumes did not include a negative value in any year.
[10] Remaining methodologies include the 3-year weighted average methodology used by Union rate zone, the 3-year simple average and the 5-year simple average.

yearly absolute percent errors, where the absolute percent error in any year is the absolute error divided by the actual value[11].

14. The term "out-of-sample" as referenced in the paragraph above means that the model incorporates only a portion of the sample. For instance, to measure forecasting accuracy for 2017, the forecast is generated using the historical actual data up to 2015. That forecast is then compared to the 2017 actual recorded value for UFG to determine the absolute error and absolute percent error as provided in Table 2. This approach is comparable to annual forecasting processes utilized by Enbridge Gas, such as the degree day forecast and the average use forecast, which employ a 2-year lag of data, whereas the test year forecasts employ a 3-year lag of data (as the forecast for 2024 includes actual results up to 2021).

15. Table 2 shows the results of the statistical analysis of the forecasting methodologies evaluated, based on the approach described above.

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11 $MAPE = \frac{1}{N}\sum_{i=1}^{N}\left(\frac{|Forecast_i - Actual_i|}{Actual_i}\right)$

Table 2

Unaccounted for Gas (in 10^3m^3) Forecast Accuracy Comparison

Line No.	Year	Actual UFG Volumes	Out-of-Sample Forecast: Union Current	Out-of-Sample Forecast: 3-yr average	Out-of-Sample Forecast: 5-yr average	Absolute Errors: Union Current	Absolute Errors: 3-yr average	Absolute Errors: 5-yr average	Absolute Percent Errors: Union Current	Absolute Percent Errors: 3-yr average	Absolute Percent Errors: 5-yr average
		(a)	(b)	(c)	(d)	(e)=(a-b)	(f)=(a-c)	(g)=(a-d)	(h) = (e/a)	(i)=(f/a)	(j)=(g/a)
1	2017	201,978	161,181	195,564	167,833	40,797	6,414	34,145	20%	3%	17%
2	2018	278,533	161,840	213,345	198,969	116,694	65,189	79,565	42%	23%	29%
3	2019	278,246	150,186	203,174	210,674	128,061	75,072	67,572	46%	27%	24%
4	2020	184,354	174,690	248,404	224,109	9,665	64,049	39,755	5%	35%	22%
5	2021	325,670	171,231	252,919	233,261	154,439	72,751	92,409	47%	22%	28%
6				MAE (2017-2021)		89,931	56,695	62,689			
7				MAPE (2017-2021)					32%	22%	24%

16. The MAE and MAPE results in Table 2 indicate that the 3-year simple average methodology results in the smallest forecast error. It is therefore the most accurate forecast when using the last five years of actual UFG data (historical UAF volumes for the EGD rate zone and historical UFG volumes for the Union rate zone), in comparison to the current Union rate zone 3-year weighted average methodology of the ratio of UFG volumes to total system throughput and the 5-year simple average methodology. On that basis, Enbridge Gas is recommending the 3-year simple average methodology for the determination of the forecast for UFG volumes for the amalgamated utility starting in 2024.

17. Implementation of the harmonized UFG forecasting methodology and the resulting UFG volume forecast aligns with the implementation of a common reference price. The harmonized UFG volume forecast is part of the total volume forecast that is used to determine total supplies required. The supply requirements underpin the harmonized gas supply plan which is used in the derivation of the single harmonized reference price. The proposed harmonized UFG forecast and proposed harmonized Gas Supply Plan are not broken down by rate zone, which necessitates the requirement for a common reference price. The common reference price also ensures all customers pay the same gas cost unit rate for UFG. The proposed harmonized reference price and the methodology for its determination is provided at Exhibit 4, Tab 2, Schedule 2.

18. Variances between actual UFG volumes and costs and forecasted UFG volumes and costs are proposed to be recovered through a harmonized UFG variance account which is provided at Exhibit 9, Tab 1, Schedule 2.

3. Historical and Forecast Information Relating to UFG Volumes and Cost

19. The 2024 Test Year Forecast for UFG is $56.1 million, based on the proposed harmonized 3-year simple average forecasting methodology[12]. The forecasts for the 2022 Estimate and 2023 Bridge Year are based on the existing methodologies for the respective rate zones previously described in this Exhibit. Historical UFG volumes and costs for 2013 to 2021, the 2022 Estimate, 2023 Bridge Year and 2024 Test Year Forecast, as well as the calculation of year-over-year variances, are provided at Attachments 1 and 2, respectively.

20. A summary of UFG volumes for 2019 to 2024 is provided in Table 3.

[12] Based on consolidated actual UFG data, including historical UAF volumes for the EGD rate zone and historical UFG volumes for the Union rate zones from 2019 to 2021 and historical LUF volumes from the EGD rate zone from 2020 to 2021.

Table 3
UFG Volumes

Line No.	Particulars (10^3m^3)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)
1	UAF / LUF Volumes	EGD (1)	160,960	130,599	135,918	127,042	127,042	
2	UFG Volumes	Union (2)	121,079	66,056	223,637	73,375	81,738	
3	UFG Volumes	EGI						270,370
4	Total		282,038	196,655	359,555	200,418	208,781	270,370
5	Year-over-Year Variance			(85,383)	162,900	(159,137)	8,363	61,589

Notes:
(1) EGD rate zone.
(2) Union rate zones.

21. A summary of UFG costs for 2019 to 2024 is provided in Table 4.

Table 4
UFG Costs

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)
1	UAF / LUF Cost	EGD (1)	26.1	19.0	24.8	21.1	29.4	
2	UFG Cost	Union (2)	15.7	7.5	35.9	10.0	16.8	
3	UFG Cost	EGI						56.1
4	Total		41.8	26.5	60.6	31.1	46.2	56.1
5	Year-over-Year Variance			(15.4)	34.2	(29.6)	15.1	9.9

Notes:
(1) EGD rate zone.
(2) Union rate zones.

22. Variance analysis of the year-over-year changes in UFG costs is included in Table 5. Variances are driven by changes in the level of actual and forecasted UFG volumes, as well as changes in the reference price.

Table 5
Unaccounted for Gas Year-over-Year Variances

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)
1	Prior Year UFG Cost		42.4	41.8	26.5	60.6	31.1	46.2
2	Increase/(Decrease) - UFG Throughput	EGD (1)	(0.2)	(4.9)	0.8	(1.5)	0.0	
3	Increase/(Decrease) - Reference Price	EGD	(0.1)	(2.2)	5.0	(2.1)	8.2	
4	Increase/(Decrease) - UFG Throughput	Union (2)	(0.1)	(7.2)	17.9	(24.1)	1.1	
5	Increase/(Decrease) - Reference Price	Union	(0.1)	(1.1)	10.5	(1.8)	5.8	
6	Increase/(Decrease) - UFG Throughput	EGI						9.5
7	Increase/(Decrease) - Reference Price	EGI						0.4
8	Total Variance		(0.6)	(15.4)	34.2	(29.6)	15.1	9.9
9	Current Year UFG Cost		41.8	26.5	60.6	31.1	46.2	56.1

Notes:
(1) EGD rate zone.
(2) Union rate zones.

23. The 2024 Test Year Forecast of UFG is $56.1 million. The $9.9 million increase from the 2023 Bridge Year Forecast to the 2024 Test Year Forecast is primarily attributable to the higher UFG volumes forecasted based on the proposed 3-year simple average forecast methodology. The UFG volume forecast under the

proposed methodology is based on the actual UFG volumes from 2019 to 2021. The 3-year simple average of UFG volumes for 2019 to 2021 is higher than the current OEB-approved UFG volume forecasts for the EGD and Union rate zones under the existing methodologies. Variances between the OEB-approved UFG volume forecast and actual results for 2019 to 2021 have been addressed through the annual Earnings and Disposition of Deferral and Variance Account Disposition proceedings. The 2021 proceeding included a discussion of drivers of higher than forecast UFG volumes.[13]

24. The 2023 Bridge Year Forecast of UFG is $46.2 million, which is a $15.1 million increase from the 2022 Estimate to the 2023 Bridge Year Forecast. $14 million of the increase is attributable to the increase in reference prices in each respective rate zone. There is also a $1.1 million increase in the Union rate zones attributable to a throughput variance. In the Union rate zones, the UFG volume forecast is based on an OEB-approved ratio of UFG volumes to total system throughput volumes. For 2023, the total system throughput volumes are forecasted to be higher than 2022, which drives a UFG throughput variance when applied to the OEB-approved UFG ratio. The details of the increase in the volumes forecasted are provided at Exhibit 3, Tab 3, Schedule 1, Attachment 7.

25. The 2022 Estimate is $31.1 million, which is a $29.6 million decrease from the 2021 actuals. $25.6 million of the decrease is attributable to lower UFG volumes forecasted, based on existing OEB-approved methodologies, in 2022 relative to the actual UFG volumes recorded in 2021, primarily in the Union rate zones. There is also a $3.9 million decrease attributable to lower reference prices forecast in each rate zone in 2022 versus 2021.

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[13] EB-2022-0110.

26. The 2021 actual is $60.6 million, which is a $34.2 million increase from 2020 actuals. $18.6 million of the increase is attributable to higher UFG volumes experienced in 2021, particularly in the Union rate zones, in comparison to 2020 actuals. There is also a $15.5 million increase attributable to higher reference prices in each rate zone in 2021 versus 2020.

27. The 2020 actual is $26.5 million, which is a $15.4 million decrease from 2019 actuals. $12.1 million of the decrease is attributable to lower UFG volumes experienced in 2020 across all rate zones, in comparison to 2019 actuals. There is also a $3.3 million decrease attributable to lower reference prices in each rate zone in 2020 versus 2019.

4. Directives and Commitments from Previous Regulatory Applications

28. The following evidence addresses directives from the OEB and commitments made by Enbridge Gas in previous regulatory applications.

4.1. UFG Results by Rate Zone and Activity

29. As part of the 2020 Rates proceeding[14], Enbridge Gas committed to report on UFG results, segregated by rate zone and activity, with the most recent historical information for the 2024 Rebasing Application. This commitment was in response to concerns raised by intervenors that the 2019 UFG Report filed as part of the 2020 Rates Application did not provide an “apples to apples” comparison of UFG results for the legacy utilities and requested that Enbridge Gas provide more segregated and complete information about UFG measurement across the constituent parts of Enbridge Gas’s combined system.

[14] EB-2019-0194, Decision and Order, May 14, 2020, p.19.

30. The integrated nature of Enbridge Gas's distribution, transmission and storage operations as well as the element of UFG that is unknown and not specifically measurable limits the ability of Enbridge Gas to provide measured volumes of UFG segregated by rate zone and activity. This commitment has been addressed by presenting the most recent historical actual UFG volumes from 2021 consistent with the allocation to rate classes of the UFG deferral account balances in the Company's 2021 Utility Earnings and Disposition of Deferral and Variance Account proceeding[15]. Enbridge Gas has presented the 2021 actual UFG volumes as distribution, transmission and storage functions consistent with the OEB-approved methodologies for each rate zone, with one adjustment, described below, in order to provide comparability across rate zones.

31. For the purposes of splitting actual 2021 UFG volumes by rate zone, Enbridge Gas has reported the Union South rate zone in-franchise delivery volumes as distribution UFG, rather than transmission per OEB-approved methodology, which is consistent with the EGD rate zone methodology for similar UFG amounts. It was not necessary to make the same adjustment for the Union North rate zone because Union's OEB-approved methodology allocates UFG for Union North in-franchise customers based on transmission volumes not delivery volumes.

32. In addition, Enbridge Gas has continued to report the Rate M12 transportation and Rate M16 storage activity for the EGD rate zone as ex-franchise transmission activity, which is based on the contracts that existed between EGD and Union prior to amalgamation. This approach is consistent with the existing Union rate zones methodology.

[15] EB-2022-0110.

33. The breakdown of UFG volumes by rate zone and activity as described above for 2021 is provided in Table 6.

Table 6
2021 UFG Volumes by Rate Zone and Activity

Line No.	Particulars (10^3m^3)	Delivery	Transmission	Storage	Total UFG Volumes
		(a)	(b)	(c)	(d)
1	EGD	94,843	-	41,075	135,918
2	Union	55,005	148,625	20,007	223,637
3	Total	149,848	148,625	61,082	359,555

4.2. Impact of Increasing Storage Pool Pressure Gradient on UFG

34. As part of the 2021/2022 Storage Enhancement Project proceeding, OEB Staff submitted questions about the impact of increasing the storage pool pressure gradient on indirect costs, and particularly on UFG.[16] OEB Staff later submitted that Enbridge Gas should be directed to monitor and report back on the impact that increases in the pressure gradient and increased deliverability capability may have on UFG on all existing and new storage enhancement projects.[17] In its reply submission, Enbridge Gas stated that it will address the impact of increasing the pressure gradient on UFG as part of its next rebasing application.[18]

35. In this evidence, Enbridge Gas has assessed the potential impact of increasing storage pool pressure gradient on UFG by analyzing historical storage pool inventory adjustments. These adjustments are completed periodically to reflect a difference between measured and observed levels of storage pool inventories, with the differences considered as UFG. Analysis was completed to assess whether a

[16] EB-2020-0256, Exhibit I.STAFF.3 part d) and e).
[17] EB-2020-0256, OEB Staff Submission, March 3, 2021, p.5.
[18] EB-2020-0256, Enbridge Gas Reply Submission, March 15, 2021, p.8.

correlation exists between increasing storage pool pressure gradients and the magnitude and direction of storage pool inventory adjustments.

36. The inventory in all of Enbridge Gas's underground storage pools is monitored on an ongoing basis. Inventory in and out of the storage pools is recorded using both flow and pressure measurement. Flow measurement is the official form of measurement and is used to track storage pool inventory balances. Information from the flow and pressure measurement is used to develop trends for each pool and identify the appropriate adjustments to the measured inventory. These adjustments are required to correct measurement errors and account for the migration of gas within the reservoir.

37. Increasing the pressure gradient in a storage pool creates additional storage capacity. Enbridge Gas has increased the pressure gradient for all its storage pools above their discovery gradient, in both the EGD and Union rate zones.

38. In 2020 and 2021, Enbridge Gas increased the pressure gradient in six storage pools in the EGD rate zone above 0.7 psi/ft. Given the recency of these projects, there is not sufficient data to determine if increasing the pressure gradient in these pools has had any impact on UFG.

39. Enbridge Gas in the Union South rate zone has a more extensive history of increasing the pressure gradient in its storage pools. As such, historical data from the storage pools within the Union South rate zone has been used for the analysis of the impact of increased pressure gradient on UFG. Prior to 2002, the pressure gradient in storage pools in the Union rate zone was 0.70 psi/ft. From 2002 to 2011, the pressure gradient was increased to 0.73 psi/ft gradient in 15 of the storage pools in the Union South rate zone. From 2012 to 2021, the pressure gradient was

increased to 0.76 psi/ft gradient in 13 of the storage pools in the Union South rate zone.

40. Enbridge Gas has assessed the potential impact of the increasing the pressure gradient in its storage pools on UFG by analyzing the adjustments to storage pool inventories associated with the storage pools in the Union South rate zone, such that adjustments to storage pool inventories represent UFG. Table 7 includes a summary of the total adjustments to storage pool inventories during the time period in which storage enhancement projects have been undertaken.

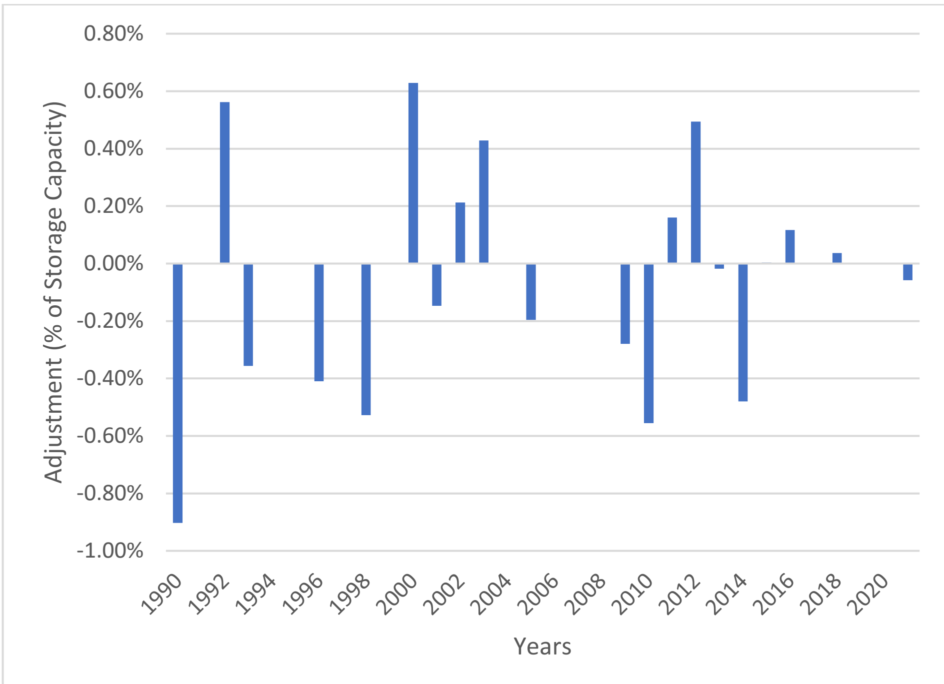
Table 7
Adjustments to Storage Pool Inventories

Line No.	Years	Total Adjustments (10^3m^3)	Average Annual Adjustment (10^3m^3/year)
		(a)	(b)
1	1992-2001	(7,443)	(744)
2	2002-2011	(10,198)	(1,020)
3	2012-2021	3,994	399

41. Table 7 shows that, in the 10-year period of 1992 to 2001 prior to the completion of storage enhancement projects, the average annual storage adjustment was a reduction of inventory of 744 10^3m^3. For the two subsequent 10-year periods of 2002 to 2011 and 2012 to 2021, the average annual adjustments were a reduction of 1,020 10^3m^3 and an increase of 399 10^3m^3 respectively. The results in Table 7 do not provide conclusive evidence of a correlation between increasing the pressure gradient in the Union South rate zone storage pools and the adjustments to storage pool inventories.

42. Figure 1 provides further detail and presents the storage adjustments by year as a percentage of total storage capacity.

Figure 1: Adjustments to Union South Rate Zone
Storage Pool Inventories (By Year)



43. The data presented in Table 7 and Figure 1 indicate that there is not a conclusive trend or correlation as it relates to the magnitude of the average annual adjustments nor in the direction (increase or decrease) of the adjustments that can be attributed to be a result of increasing pressure gradient on Enbridge Gas's storage pools.

4.3. Implementation of Recommendations from 2019 UFG Report

44. As part of the Decision and Order for Enbridge Gas's 2020 Rate Application[19], Enbridge Gas committed to report on its progress in implementing the recommendations set out in the 2019 UFG Report in the 2022 Rates Application. In

[19] EB-2019-0194, OEB Decision and Order, May 14, 2020.

response to that commitment, Enbridge Gas filed a progress report in its 2022 Rate Application[20]. However, the OEB determined that issues related to UFG were out of scope for that proceeding and that the progress report and other updates as it relates to the implementation of recommendations from the 2019 UFG report would be considered as part of the 2024 Rebasing proceeding.

45. In accordance with the OEB direction, the UFG Progress Report, as originally filed in the 2022 Rate Application, has been provided at Attachment 3. Updates noted in the UFG Progress Report include:
    a) Implementation of a harmonized leak operating standard;
    b) Development of a three-year program to eliminate backlog of leaks identified prior to the roll out of the new standard;
    c) Adoption of best practices in the area of controlled releases of gas during maintenance and construction activities;
    d) Implementation of a more robust leak detection and report (LDAR) program within Storage and Transmission operations;
    e) Implementation of a measurement and compliance program with respect to compressor venting;
    f) Implementation of a program to replace continuous high bleed pneumatic devices;
    g) Utilization of an incinerator during pipeline maintenance activities to combust the gas entering the atmosphere rather than venting methane;
    h) Development of a damage reduction strategy;
    i) Standardization of meter shop testing processes;
    j) Standardization of super compressibility factors;

[20] EB-2021-0148.

k) Alignment and standardization of best practices for the Gas Measurement function and Gas Measurement Accounting System;
l) Creation of a cross-functional measurement working group;
m) Completion of the redesign of the Victoria Square Gate Station; and
n) Refinement of the tracking and recording of company use gas.

46. A secondary progress report, which includes updates since the filing of the first UFG Progress Report, is provided at Attachment 4. Updates noted in the Supplemental UFG Progress Report include:
   a) Updated benchmarking analysis, relative to the same peer group from the 2019 Report on UFG, showing that Enbridge Gas continues experiences lower levels of UFG as a percentage of throughput in comparison to its peers;
   b) Updated reporting of lost gas from leaks and emissions;
   c) Development and implementation of a scope 1 and scope 2 emission reduction strategy;
   d) Updated reporting of retail meter test results;
   e) Harmonization of applications used for large volume customer meter measurement and consistent volume measurement data validation;
   f) Updated reporting of custody versus check measurement differences;
   g) Installation of additional measurement at interconnect site; and
   h) Initiation of system application change to refine unbilled sales estimates.

UFG Volumes

Line No.	Particulars (10^3m^3)	Utility	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)
1	UAF / LUF Volumes	EGD	121,125	159,143	112,201	153,478	113,443	162,451
2	UFG Volumes	Union	98,596	87,014	47,204	114,166	95,887	121,984
3	Total		219,721	246,158	159,405	267,643	209,330	284,435
4	Year-over-Year Variance			26,437	(86,752)	108,238	(58,313)	75,105

UFG Volumes

Line No.	Particulars (10^3m^3)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)
1	UAF / LUF Volumes	EGD (1)	160,960	130,599	135,918	127,042	127,042	
2	UFG Volumes	Union (2)	121,079	66,056	223,637	73,375	81,738	
3	UFG Volumes	EGI						270,370
4	Total		282,038	196,655	359,555	200,418	208,781	270,370
5	Year-over-Year Variance			(85,383)	162,900	(159,137)	8,363	61,589

Notes:
(1) EGD rate zone.
(2) Union rate zone.

UFG Costs

Line No.	Particulars ($ millions)	Utility	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
			(a)	(b)	(c)	(d)	(e)	(f)
1	UAF / LUF Cost	EGD	20.3	32.7	23.3	25.8	20.2	26.4
2	UFG Cost	Union	19.6	16.5	9.1	21.0	13.8	16.0
3	Total		39.8	49.2	32.5	46.8	34.0	42.4
4	Year-over-Year Variance			9.4	(16.7)	14.3	(12.7)	8.4

UFG Costs

Line No.	Particulars ($ millions)	Utility	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)	2023 Bridge Year (e)	2024 Test Year (f)
1	UAF / LUF Cost	EGD (1)	26.1	19.0	24.8	21.1	29.4	
2	UFG Cost	Union (2)	15.7	7.5	35.9	10.0	16.8	
3	UFG Cost	EGI						56.1
4	Total		41.8	26.5	60.6	31.1	46.2	56.1
5	Year-over-Year Variance			(15.4)	34.2	(29.6)	15.1	9.9

Notes:
(1) EGD rate zone.
(2) Union rate zone.

ENBRIDGE GAS INC.

PROGRESS REPORT ON IMPLEMENTATION OF SCOTTMADDEN RECOMMENDATIONS ON UNACCOUNTED FOR GAS (UFG)

CONTENTS

1.0 INTRODUCTION

1.1 PURPOSE

In its 2016 Earnings Sharing and Deferral Account Disposition proceeding (EB 2017-0102), legacy Enbridge Gas Distribution agreed to review potential metering issues that might be contributing to Unaccounted for Gas (UFG) and to report on that review as part of the 2018 Rate Adjustment Application[1]. In the 2018 Rate Application, Legacy Enbridge Gas Distribution agreed to continue this review and report on it as part of the 2019 Rate Adjustment Application.[2] In the MAADs decision EB-2017-0306/EB-2017-0307, the Ontario Energy Board (OEB) directed Enbridge Gas Inc (Enbridge Gas or EGI) to file a report on UFG for both legacy Union Gas (LUG) and legacy Enbridge Gas Distribution (LEGD) service areas by December 31, 2019. Accordingly, Enbridge Gas filed a UFG report (the UFG Report) prepared by ScottMadden Management Consultants in December 2019. The UFG Report reviewed and evaluated factors contributing to UFG for the legacy Companies. The Report indicated that the main sources of UFG included retail meter variations, gate station meter variations, leaks, fugitive emissions, third-party theft, company use and accounting adjustments.

The UFG Report was considered as part of the 2020 Rate Application Phase 2 (EB-2019-0194). In that proceeding, Enbridge Gas committed to "….report upon its progress in implementing the recommendations set out in the UFG Report in its 2022 rates filing."[3] Enbridge Gas has also committed in the same application[4] 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. Furthermore, Enbridge Gas committed[5] to provide reporting of UFG results, segregated by rate zone and activity (distribution, transmission, storage), with the most recent historical information as part of the rebasing filing.

Enbridge Gas has always monitored and actively managed UFG. The UFG Report provided numerous recommendations to enhance the ongoing efforts already in place. This update provides details of Enbridge Gas' progress in implementing the recommendations set out in the UFG Report. The recommendations from the UFG Report were to "identify and standardize "best practices" across the legacy

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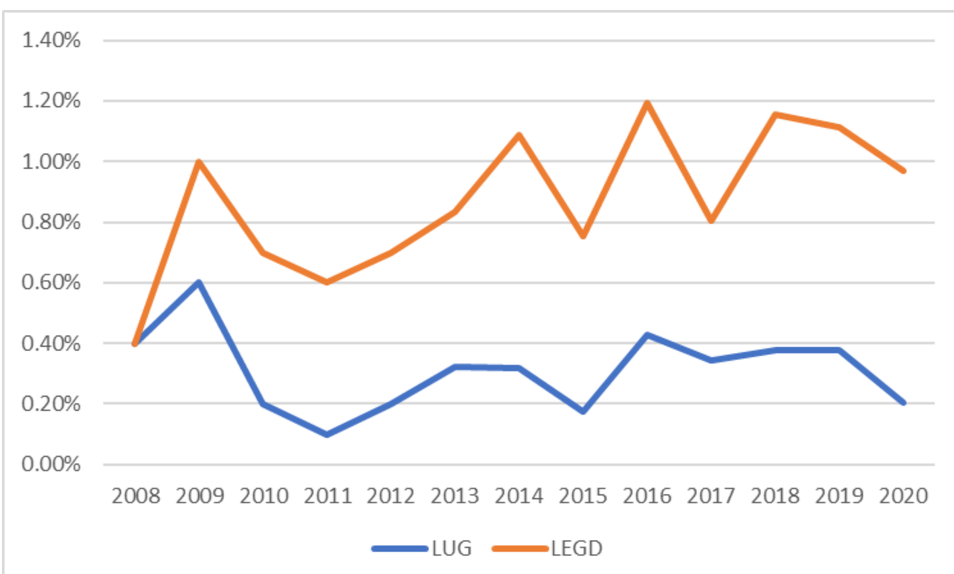
[1] EB-2017-0102, Settlement Proposal, page 14.
[2] EB-2017-0086, Settlement Proposal, Exhibit N2, Tab 1, Schedule 1, page 12.
[3] EB-2019-0194, Reply Argument of Enbridge Gas dated May 1, 2020, page 33; EB-2019-0194, Decision and Order dated May 14, 2020, page 20.
[4] EB-2019-0194, Reply Arguement, page 34.
[5] EB-2019-0194, Reply Arguement, page 34

Companies…..document data, processes and studies related to monitoring and managing UFG……[and] investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG"[6]. This update outlines how Enbridge Gas is actively taking steps to implement the recommendations from the UFG Report, while continuing to prudently monitor and manage UFG.

1.2 Unaccounted For Gas (UFG) Overview

UFG is broadly defined as the difference between gas receipts and gas deliveries, where gas receipts are volumes that enter the distribution system and gas deliveries are volumes that exit the distribution system. Gas receipts generally include gas supplies from pipeline and withdrawals from on-system storage facilities, while gas deliveries generally include sales to retail customers and injections into on-system storage facilities. The UFG Report included benchmarking analysis that demonstrated that UFG as a percentage of throughput for both legacy Companies was lower than its peers. Figure 1 shows UFG as a percentage of throughput for both legacy Companies. UFG as a percentage of throughput for both legacy Companies has remained flat or decreased for the last five years.

Figure 1: UFG as a % of Throughput for LUG and LEGD



[6] EB 2019-0194, ScottMadden Report, December 2019, page 47.

Figure 2: Historical UFG Volumes and % of Throughput

Year	LEGD UFG Volume (103m3)	LUG UFG Volume (103m3)	LEGD UFG as a % of Throughput	LUG UFG as a % of Throughput
2008	44,424	143,880	0.373%	0.411%
2009	110,917	201,845	0.981%	0.637%
2010	72,104	67,283	0.662%	0.192%
2011	73,355	35,668	0.647%	0.105%
2012	74,762	68,690	0.711%	0.210%
2013	97,361	113,997	0.834%	0.320%
2014	135,380	97,109	1.089%	0.318%
2015	88,438	54,408	0.752%	0.174%
2016	133,112	131,588	1.194%	0.427%
2017	93,077	108,901	0.804%	0.342%
2018	142,086	136,447	1.157%	0.379%
2019	140,594	137,652	1.114%	0.376%
2020	110,234	74,120	0.968%	0.208%

2.0 Main Sources of UFG

Overview

As part of its research and analysis for the UFG Report, ScottMadden identified certain common sources of UFG across the industry, including physical losses (eg.leaks, third-party damage and venting during construction and maintenance activities), metering variations, non-registering meters, theft, line pack and billing and accounting adjustments. ScottMadden also determined that the sources of UFG for the legacy Companies were generally consistent with those at other gas utilities. The following sections provide additional detail regarding the sources of UFG at Enbridge Gas.

2.1 Physical Losses

Physical losses are a source of UFG at Enbridge Gas. Contributors to physical losses include: leaks and emissions from natural gas facilities, releases of natural gas during maintenance, construction and emergency situations, and line hits due to third-party construction or excavation activities.

Enbridge Gas reports fugitive, vented and flared emissions annually to Environment and Climate Change Canada and the Ontario Ministry of Environment, Conservation and Parks. Figure 3 shows a 15% decline in emissions and leaks within the consolidated Enbridge Gas operations from 2015 to 2020. The slight increase in leaks and fugitive emissions reported in 2019 and 2020 is a result of the use of improved emissions factors. Since 2018, Enbridge Gas continues to refine the emissions and activity factors used to quantify and estimate leaks and fugitive emissions. Changes to these factors are described in EGI Interrogatory Response (EB-2019-0194, Exhibit I.STAFF.30), as well as in section 3.1 (iii) of this report. Figure 3 shows lost gas from leaks and emissions on a combined basis for Enbridge Gas, while Figure 4 provides a breakdown of the total leaks and emissions for Enbridge Gas by type.

Figure 3: Lost Gas from Leaks and Emissions ($10^6 m^3$)

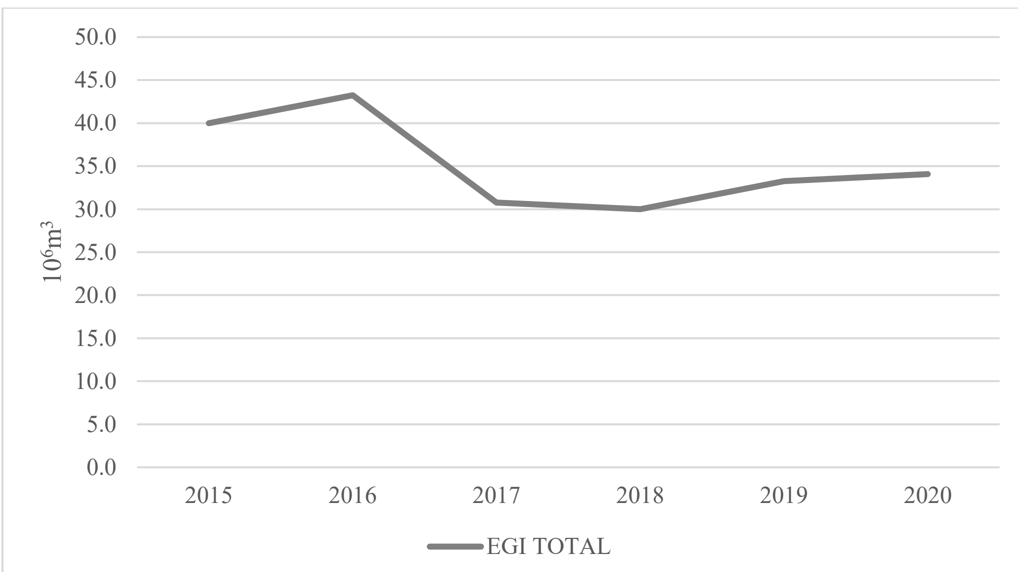
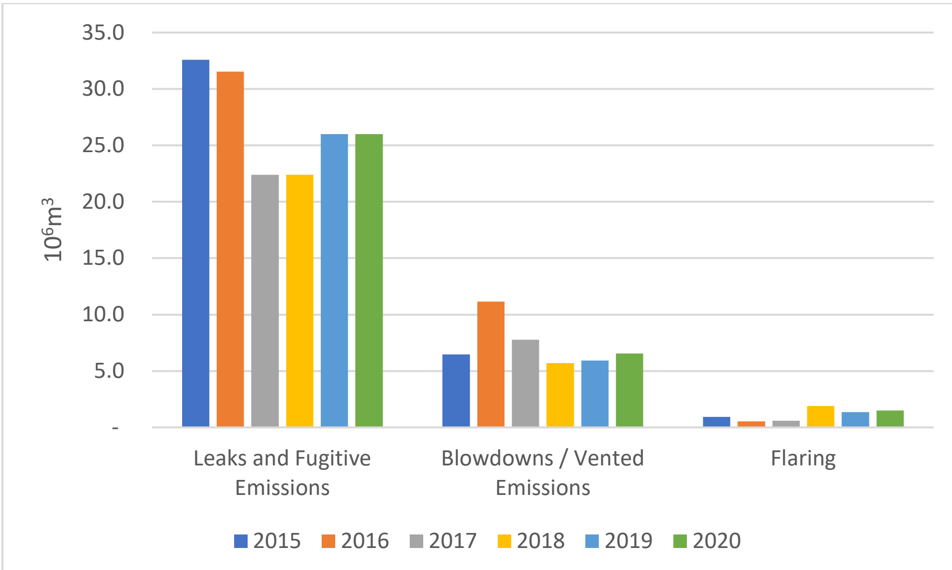


Figure 4: Lost Gas from Leaks and Emissions (10^6m^3) by Type



2.2 <u>Retail Meter Variations</u>

Retail meter variations represent variations between actual and metered volumes at customer locations. These variations can be attributed to factors including: inherent measurement uncertainties of meters, meter failure, inaccurate corrections for temperature and pressure variations or improperly sized meters. Enbridge Gas conducts meter testing on a sample of diaphragm meters annually. These tests are conducted under low-flow and high-flow conditions. Historical test results going back to 2014 are shown in Figure 5 and 6 below.

Figure 5: LEGD Meter Test Results vs Measurement Canada (MC) Standard

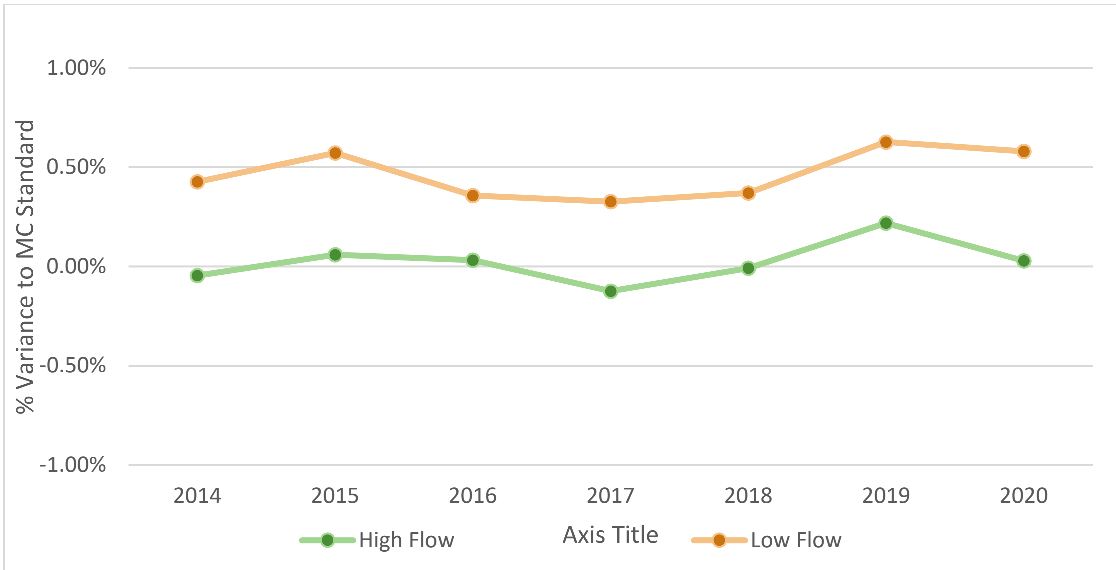


Figure 6: LUG Meter Test Results vs Measurement Canada (MC) Standard

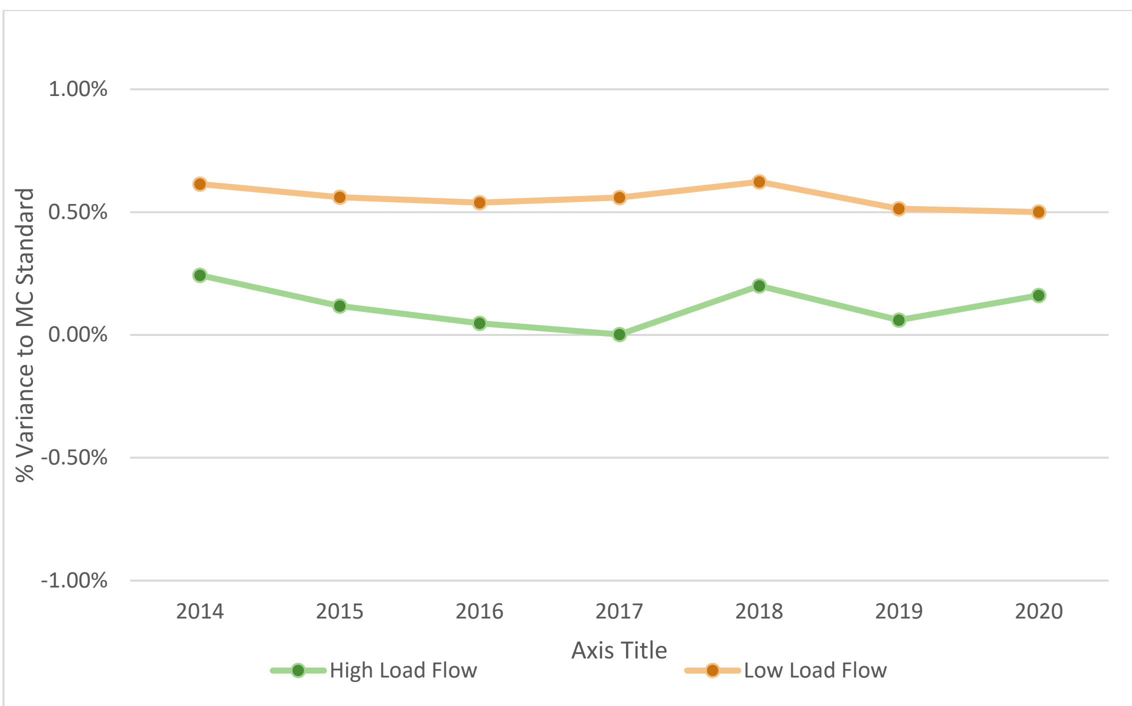


Figure 5 and 6 show that tests under high-flow and low-flow conditions result in the following variances since 2014:

	High-Flow Conditions % Variance to Measurement Canada Standard	Low-Flow Conditions % Variance to Measurement Canada Standard
LEGD	0.02%	0.47%
LUG	0.12%	0.56%

The variances to the Measurement Canada standard are within the Measurement Canada tolerance of +/- 3.0 percent. Meters whose test results that fall outside of the +/- 3.0 percent tolerance are taken out of service. All rotary turbine, and ultrasonic meters are tested on a frequency which is prescribed by Measurement Canada[7].

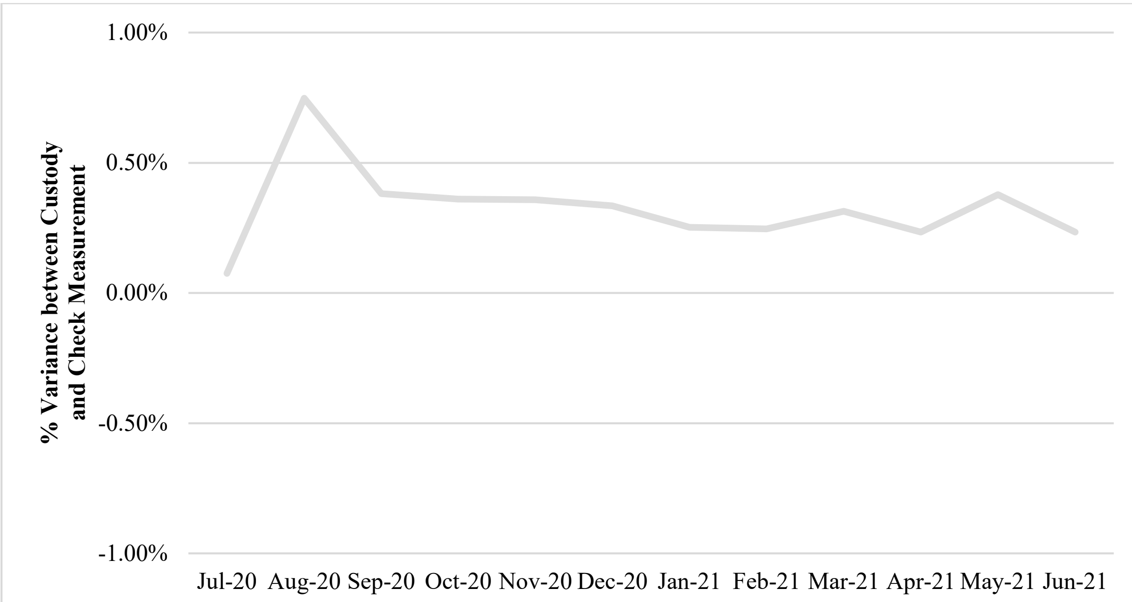
2.3 Gate Station Meter Variations

Gate station meter variations represent a potential source of UFG if there are differences at receipt points between actual and metered volumes. However, not all gate station meter variations can be wholly attributable to UFG, as the variations may only represent differences in meters, and may not represent actual lost gas.

Enbridge Gas utilizes check meters to validate the accuracy of the custody or supplier meters. A comparison between Enbridge Gas' check meters and third-party custody transfer meters is depicted in Figure 7 below. This figure demonstrates that Enbridge Gas' check measurement falls within the Measurement Canada prescribed range of +/- 3% and with the +/- 2% tolerance of the Enbridge Gas internal benchmark.

[7] Gas Bulletin G-18: Reverification periods for gas meters, ancillary devices and metering installations (http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00607.html) and
Gas Bulletin G-03: Natural gas meters and ancillary devices qualified for a lengthened initial reverification period, identifies meter manufacturers and models (http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00576.html)

Figure 7: Third Party Custody Transfer vs Enbridge Gas Check Meters Differences



2.4 OTHERS *(INCL. ACCOUNTING ADJUSTMENTS, COMPANY USE, THEFT AND NON-REGISTERING METERS)*

The remaining primary contributors of UFG at Enbridge Gas include theft and non-registering meters, company use, and accounting adjustments. Theft and non-registering meters account for volumes that are not metered or recorded due to unauthorized use or faulty equipment. Company use contributor represents the portion of company use volumes used by Enbridge Gas that are not metered and/or recorded. Accounting adjustments represent variations between actual and reported volumes due to various accounting adjustments, including unbilled sales adjustments, billing adjustments, line pack and other accounting related adjustments.

3.0 UPDATE ON RECOMMENDATIONS BY SOURCE

SUMMARY OF SCOTTMADDEN RECOMMENDATIONS

In the UFG Report, ScottMadden recommended that Enbridge Gas identify and standardize “best practices” across the legacy Companies. ScottMadden also recommended that Enbridge Gas document data, process and studies related to monitoring and managing UFG. Finally, ScottMadden recommended that, on a periodic basis, Enbridge Gas investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG. In addition to these general recommendations, ScottMadden also provided recommendations specific to each of the main sources of UFG. The following sections highlight the work that has been done for each of these recommendations in relation to each main source of UFG.

3.1 Physical Losses

i. Identify and Standardize Best Practices at EGI

Enbridge Gas implemented a harmonized leak operating standard across the legacy Companies in July 2020. This new standard includes: harmonized internal compliance requirements for leak monitoring and repair timelines, increased traceability and tracking of leak repairs (including the addition of new work order types corresponding to type and severity of leaks, an enhancement for both legacy Companies), increased monitoring frequencies and harmonized repair timelines for above ground leaks (which increased the frequency of monitoring for LEGD assets to align with the LUG standard), harmonization of survey cycles based on asset age and pressure (designed to survey assets with higher probability of failure on a more frequent cycle), and initiation of the station leak survey program.

In conjunction with the new leak operating standard, Enbridge Gas has developed a three-year program to eliminate a backlog of leaks identified prior to the roll out of the new standard.

In the area of controlled releases of gas during maintenance and construction activities, Enbridge Gas has been able to leverage best practices across the legacy Companies. LUG historically relied on lower pressure markets, where available, to draw down sections of pipeline for construction and maintenance, with the remaining gas vented to atmosphere. Since the integration of the two legacy Companies, Enbridge Gas has been able to leverage a portable drawdown compressor previously utilized by LEGD for construction related maintenance activities across the legacy Companies service areas.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

As noted in the UFG Report, Enbridge Gas has a program to review and evaluate replacement of bare-steel mains. This is an existing program that was in place prior to the amalgamation of the two Legacy Companies, originating from the LUG Pipeline Integrity Management Program, and more recently, has been included in Enbridge Gas' Asset Management Plan. Since 2019, approximately 9,800 kms of bare-steel mains have been replaced across the Enbridge Gas service area, with a target of replacing all remaining bare-steel mains by the end of 2024.

Enbridge Gas also has a program in place to replace vintage steel and plastic mains. This program leverages the Asset Health Review (AHR) process to forecast when corrosion and crack leaks might occur. The AHR process involves an evaluation of Enbridge Gas' gas carrying assets and their characteristics. The AHR utilizes reliability and risk models, both of which were updated in 2021 with additional historical data, and in some case, updates to the methodologies used in the models. A risk assessment is developed using the results of the reliability and risk models and an evaluation of the consequences of failure. This assessment is used to proactively select main replacements.

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

Enbridge Gas continues to sponsor emissions studies, in partnership with the Canadian Energy Partnership for Environmental Innovation (CEPEI) and its member natural gas companies across Canada. The goal of these studies is to improve emission and activity factors and emission estimation methodologies in the natural gas storage, transmission and distribution industry. Recent studies have been completed to better quantify emissions related to residential, commercial and industrial meter sets, with the updated emission and activity factors results being incorporated into the Enbridge Gas emissions inventory starting with the 2019 emissions inventory. Additionally, Enbridge Gas is part of a study that is currently underway to update emission and activity factors related to valve sites. The survey work for the study was completed in 2020, and the results of the study are pending.

iv. Implement New Practices and Initiatives

Enbridge Gas has implemented new practices and initiatives relating to damage reduction and reduction of methane emissions from venting and fugitive leaks.

In 2020, the federal Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (Methane Regulation) came into effect, to help reduce methane emissions from Canada's oil and gas sector. In response to the Methane Regulation, Enbridge Gas has introduced programs and initiatives targeted at reducing fugitive and vented gas.

Enbridge Gas implemented a more robust leak detection and repair (LDAR) program within its Storage and Transmission operations in 2020. The LDAR program details the frequency of completion of leak surveys at compressor, storage and metering stations within Enbridge Gas' storage and transmission system, as well as specifying the timelines for completing leak repairs. The frequency of leak surveys increased from annually to three times per year. The goal of the LDAR program is to improve the detection and repair of leaks, resulting in a reduction in leaks and fugitive emissions, as well as reducing UFG. Additionally, results from these surveys have been incorporated into the Enbridge Gas GHG inventory, starting with the 2019 inventory.

Furthermore, starting in 2020, compressor unit rod packing and seal venting emissions are measured in order to meet regulatory emissions targets. In response to this regulatory requirement, Enbridge Gas implemented a measurement and compliance program in 2020 with respect to compressor venting, which includes measurement timelines, emission limits and repair deadlines for units that are over the limit. As such, vented emissions from this emissions source are expected to be reduced as compared to historical emissions.

Enbridge Gas has also implemented a program to replace continuous high-bleed pneumatic devices with low-bleed or no-bleed alternatives during the 2021-2022 calendar years. This will result in a reduction of vented emissions from pneumatic devices within storage and transmission operations.

Pipeline maintenance activities have begun to utilize an incinerator, which combusts the gas entering the atmosphere rather than venting methane. This practice began in 2021. The primary use has been to create the proper flow conditions on a pipeline to facilitate in-line inspections or to condition new pipelines during initial odourization, however it has the secondary benefit of reducing GHG emissions in lieu of venting.

Enbridge Gas has also developed a Damage Reduction Strategy, which commenced in 2021. This strategy includes a specific focus on reinforcement of safe excavation practices with contractors working in the vicinity of Enbridge Gas assets, increasing homeowner awareness and education on locate requirements and excavation guidelines (including the promotion of the "Call Before You Dig" program), improving in-field engagement with third party excavators, and increasing proactive efforts with respect to high risk excavators and high risk locate tickets.

The Damage Reduction Strategy supplements on-going damage prevention activities. This includes identification of high risk assets during the locate process which allows Enbridge Gas to deploy personnel to monitor and communicate safe excavation practices, deploying aircraft and field personnel to patrol high risk pipelines to ensure no unauthorized excavations are occurring, and maintaining repeat offenders list provided to the Technical Standards and Safety Authority (TSSA). This addresses the recommendation in the 2019 ScottMadden report, which recommended that Enbridge Gas "….monitor and identify disturbances around high risk assets, including aerial patrol and vital main locate identification. Communicate with third party contractors prior to excavation"[8].

3.2 Retail Meter Variations

i. Identify and Standardize Best Practices at EGI

Beginning in 2021, Enbridge Gas standardized meter shop processes by adopting LUG' accredited processes. All meters are now tested under one common process. Diaphragm meter testing continues to be conducted annually under the integrated process. The results from tests conducted under low-flow and high-flow conditions continue to be well within Measurement Canada's regulations which prescribe maximum in-service limits of error of +/- 3.0%.

As noted in the UFG Report, there has been an ongoing effort to standardize the supercompressibility factors across the legacy Companies. Gas composition parameters and supercompressibility factors are used in Electronic Volume Integrators (EVI) and Remote Terminal Units (RTUs) to calculate the conversion of gas volumes from line conditions to standard conditions. There are various methods that can be used to do the calculation and each method requires gas quality parameters in order to calculate the supercompressibility factor. Gas quality parameters are updated periodically to ensure that the parameters match the quality of measured gas.

In the absence of specific regulatory or industry requirements relating to the updating of gas quality parameters, the approach for making updates differed amounst the two legacy Companies. LUG had been routinely updating gas quality parameters since 2002, while LEGD had not. Due to outdated fixed gas quality parameters, LEGD was under-calculating supercompressibility and under-measuring volumes, resulting in an increase in UFG volumes. In 2019, LEGD aligned with LUG and adopted the practice of updating gas quality parameters and supercompressibility factors, on a specified frequency, depending on the type of equipment, as described below.

In early 2020, Enbridge Gas began to implement the update of gas quality parameters and supercompressibility factors. This initiative was referenced in the 2019 ScottMadden report where it was recommended to "review and update supercompressibility parameters to more accurately measure and record volumes at elevated pressures"[9]. Enbridge Gas has aligned practices across both legacy Companies to regularly update gas quality parameters during routine pressure regulation and measurement inspections. These inspections vary from once every 6

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[8] ScottMadden Report, December 2019, page 27
[9] ScottMadden Report, December 2019, page 31

months up to once every 5 years, depending on the station type and equipment within the station. These inspections fall under the Enbridge Gas Pressure Regulator Station Inspection Standard, which has also been updated and aligned across the two legacy Companies. The Pressure Regulator standard ensures that all stations are inspected and will have the gas quality parameters updated by 2025.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

N/A

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

Enbridge Gas stays abreast of industry practices and initiatives relating to retail measurement through its active participation in the Canadian Gas Association (CGA) Measurement and Regulation Steering Group. In addition to sharing best practices within the industry, the Steering Group also works closely with Measurement Canada, bringing forward recommendations relating to policies and regulations that impact the industry.

A focus of this working group recently has been the management of COVID-19 pandemic impacts as it relates to electricity and gas meter compliance and reverification requirements. The CGA has also recently proposed to form two working groups to address the finalization of specifications for Pressure Factor Metering and Ultrasonic Meter Specifications. The active participation with the CGA and Measurement Canada demonstrates Enbridge Gas's intent to stay abreast of and influence industry practices and initiatives.

iv. Implement New Practices and initiatives

A number of specific recommendations regarding the implementation of new practices and initiatives were noted in the UFG Report. First, it was recommended to:

> "Evaluate standardizing supercompressibility standards between interconnects and industrial customer sites to more accurately measure and record volumes. At interconnects, AGA-8 Supercompressibility standard is applied, while at industrial sites, the NX-19 standard is applied. The variation in standards can result in meters registering less than actual gas usage"[10]

[10] ScottMadden Report, December 2019, page 31

Enbridge Gas is in the midst of standardizing supercompressibility standards between interconnects and industrial customer sites. Enbridge Gas has developed a New Product Introduction process that provides direction regarding the approval of new measurement instruments, including Electronic Volume Integrators (EVIs) for use. Completion of this internal process is expected by Q1 2022. Upon completion of the process, EGI will start installing the AGA-8 Supercompressibility standard at industrial customer sites.

The 2019 UFG report also recommended to "Review Automated Meter Reading ("AMR") and Advanced Metering Infrastructure ("AMI") for improved accuracy of measured and recorded volumes". While this was called out as a new practice by ScottMadden, both legacy Companies have previously completed AMR pilot projects to explore these technologies. LEGD initiated a pilot project in 2006 and LUG initiated a pilot project in 1999. In 2021, Enbridge Gas has engaged a cross functional team to complete an updated assessment of both AMR and AMI technologies. The team is currently evaluating the costs and benefits of AMR and AMI solutions. Efforts are underway to identify Enbridge Gas' current risk profile and opportunities to reduce risk with an AMR or AMI solution. The team is also pursuing the execution of an AMI pilot program. The outcome of these evaluations will be incorporated into a proposal that will be filed with the OEB as part of the 2024 rebasing application.

3.3 GATE STATION METER VARIATIONS

i. Identify and Standardize Best Practices at EGI

As noted in the UFG report, gate station monitoring responsibilities were transferred to a specialized measurement group. Since that transition, there has been alignment and standardization of best practices for this function at Enbridge Gas, including increased monitoring of measurement data. Furthermore, the LEGD measurement data has been added to the LUG Gas Measurement Accounting System and is subject to additional automated validation checks, already utilized for LUG measurement data, including tolerances for volumes, temperature, pressure and data completeness. The measurement data for both legacy entities continues to be subject to the Sarbanes-Oxley (SOX) reporting requirement and is now consolidated within one reporting system and under the accountability of one group within Enbridge Gas.

In addition, a cross-functional measurement working group, focused on dealing with measurement issues and sharing of best practices, has been expanded to include representatives from across Enbridge Gas.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

In its 2016 Earnings Sharing and Deferral Account Disposition proceeding, LEGD agreed to review potential metering issues that might be contributing to UFG and to report on that review. LEGD also agreed to look specifically at the metering design at Victoria Square Gate Station.[11] In the LEGD amended settlement proposal in 2018 Rate Application[12], LEGD agreed to continue this review and report on its progress in the 2019 rate application. Further update was provided through the 2019 UFG Report completed by ScottMadden which was filed as part of the 2020 Rates Application Phase 2 (EB 2019-0194), noting that the project was scheduled to commence in 2020[13].

The redesign of the Victoria Square Gate Station was completed in 2020. Prior to the redesign, Victoria Square had one 30" ultrasonic meter run. The uncertainty of measurement of gas volumes with a single large meter is high, especially at low flow rates and this uncertainty of measurement can be a contributorto UFG variations. To reduce the measurement uncertainty, the Victoria Square Gate Station was upgraded to replace a single 30" meter run with 3 parallel ultrasonic meter runs: two 16" meters and a 4" meter.

The design also included staging so that the runs to each meter open or close depending on flow conditions, which provides a more accurate measurement over a greater range. This upgrade reduced the uncertainty of measurement by a factor of 1.4 (square root of the number of 16" meter runs) for normal flow rates and up to a factor of 5 for low flow rates.

The impact of the redesign of Victoria Sqare Gate Station was quantified in EGI Interrogatory Response (EB 2021-0149, Exhibit I.STAFF.10), where EGI noted that "A comparison of the measurement differences prior to the rebuild versus after the rebuild shows a reduction in volume difference from 12.4 $10^6 m^3$ to 2.65 $10^6 m^3$. While the UAF benefits can not be directly measured, as noted in the 2019 UAF study completed by ScottMadden, a primary source of UAF is gate station meter variations which improved significantly at Victoria Square Gate Station".

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

Enbridge Gas is a member of a number of international industry research organizations, such as the Pipeline Research Council International (PRCI), NYSEARCH (part of the

[11] EB-2017-0102, Exhibit I.B.EGDI.BOMA.21, filed: 2017-07-14
[12] EB-2017-0086, Exhibit N2, Tab 1, Schedule 1, page 12, filed: December 6, 2017
[13] ScottMadden Report, December 2019, page 39

Northeast Gas Association), and HYREADY (an international consortium of companies creating guidelines for preparing natural gas networks for hydrogen injection). This participation allows Enbridge Gas to keep abreast of the latest research in the area of measurement for the gas industry and apply research results to Enbridge Gas's processes and procedures in the area of measurement.

Based on the research led by PRCI relating to diagnostics and reverification intervals for ultrasonic meters, Enbridge Gas was able to optimize reverification intervals of ultrasonic meters. This included setting a 6-year reverification interval for renewed ultrasonic meters and an 8-year reverification interval for ultrasonic meters under Low Intervention Level agreement with TransCanada Energy (TCE). In addition, Enbridge Gas replaced single rotor meters with dual rotor meters, based on PRCI projects on turbine metering, which evaluated auto-adjust and self-checking capabilities of dual rotor turbine meters.

iv. Implement New Practices and initiatives

Enbridge Gas has addressed the recommendations from the UFG Report relating to gate station measurement. The report recommended reviewing meter point changes and exchanging/swapping check meters to evaluate meter bias. Enbridge Gas' Gas Measurement Integrity Team completes extensive data validation, review for completeness and monitoring, as described previously. These activities ensure alignment of check measurement with receipt point metering and trigger required action required if results are outside of acceptable tolerances.

The UFG Report also contained a recommendation to review requests for meter audits. It is routine practice for Enbridge Gas to notify and engage interconnecting parties for measurement maintenance activities, as well as witnessing measurement maintenance activities of interconnecting party's facilities. Furthermore, Enbridge Gas also facilitates requests for audits of interconnecting stations, such as the 2014 audit of Enbridge Gas' Kirkwall station by TCE. Enbridge Gas and TCE also have a Low Intervention Level (G-14) Agreement in place which specifies the frequency of measurement maintenance at Enbridge Gas' interconnections with TCE, in compliance with Measurement Canada requirements.

3.4 OTHERS *(INCL. ACCOUNTING ADJUSTMENTS, COMPANY USE, THEFT, NON-REGISTERING METERS)*

i. Identify and Standardize Best Practices at EGI

Upon amalgamation in 2019, Enbridge Gas continued to maintain separate customer billing systems within the legacy Companies until the recent transition in July 2021 to one consolidated billing system. During the period of time that the legacy Companies retained separate billing systems, there were process and policy alignment initiatives completed that were not constrained by the broader system integration effort. As it relates specifically to UFG, the customer billing teams aligned the processes relating to theft of gas, with nominal changes to process and forms.

A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term. As noted in the UFG Report "Usage estimation variances may be large enough to create an apparent negative UFG volume in a given month or, more rarely, two or three consecutive months. Negative UFG volumes on a monthly basis occur almost exclusively in the shoulder and summer months, are low in relation to total UFG volumes, and generally reverse or correct themselves within a one-year period".[14]

There have also been alignment efforts relating to the accounting for UFG. The UFG Report notes that "Presently, LUG adjusts for line pack in its calculations of UFG. In December 2019, Enbridge plans to adjust for line pack in its calculation of UFG."[15] Since the filing of the UFG Report, line pack is now included in the LEGD Unaccounted for Gas Variance Account (UAFVA) calculation, which is filed annually as part of the annual earning sharing proceeding.

ii. Document Data/Processes/Studies related to monitoring and managing UFG

N/A

[14] ScottMadden Report, December 2019, page 44
[15] ScottMadden Report, December 2019, page 46

iii. Research Industry Practices and Initiatives for Monitoring and Managing Sources of UFG

N/A

iv. Implement New Practices and initiatives

The UFG Report noted that the Legacy Companies measure, record and account for Company use on a monthly basis[16]. Enbridge Gas has continued to refine the tracking and recording of company use. Since 2019, gas used in company-owned vehicles is also included in the calculation of company use, which has reduced the amount of UFG recorded associated with that gas use.

4.0 SUMMARY

Since 2019, Enbridge Gas has actively addressed the recommendations outlined in the UFG Report. In addition to a number of specific recommendations, ScottMadden also recommended to identify and standardize "best practices" across the legacy Companies, document data, processes and studies related to monitoring and managing UFG, and investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG". This progress report demonstrates the actions taken for each source of UFG to address the recommendations laid out by ScottMadden.

As noted in EB 2019-0194, Enbridge Gas will provide further information in the upcoming rebasing proceeding regarding subsequent efforts to address the UFG Report's recommendations and other activities to address UFG and how these measures have impacted Enbridge Gas's UFG. Enbridge Gas will also present a proposal for consistent forecasting of UFG across its full service area and will report actual UFG results, segregated by rate zone and activity (distribution, transmission, storage) using the most recent historical information available.

[16] ScottMadden Report, December 2019, page 42

UNACCOUNTED FOR GAS
SUPPLEMENTAL PROGRESS REPORT

1. The purpose of this evidence is to report on progress in implementing the recommendations set out in the Report on Unaccounted for Gas (UFG) considered as part of the 2020 Rate Application[1]. This report is a supplement to the UFG Progress Report, as originally filed in the 2022 Rate Application,[2] provided at Exhibit 4, Tab 3, Schedule 1, Attachment 3.

2. This evidence is organized as follows:
    1. Background
    2. Benchmarking Analysis
    3. Updates on UFG by Source

1. Background

3. In its 2016 Earnings Sharing and Deferral Account Disposition proceeding[3], EGD agreed to review potential metering issues that might contribute to UFG and to report on that review as part of the 2018 Rate Adjustment Application. In the 2018 Rates proceeding[4], EGD agreed to continue the review and report on it as part of the 2019 Rate Adjustment Application.

4. In the MAADs Decision[5], the OEB directed Enbridge Gas to file a report on UFG for both the EGD and Union rate zones by December 31, 2019. Enbridge Gas filed a

[1] EB-2019-0194.
[2] EB-2021-0148.
[3] EB-2017-0102.
[4] EB-2017-0086, Settlement Proposal, Exhibit N2, Tab 1, Schedule 1, December 6, 2017, p.12.
[5] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.

Report on Unaccounted for Gas (Report on UFG) prepared by ScottMadden Management Consultants in December 2019.

5. The Report on UFG was considered as part of the 2020 Rate Application Phase 2[6]. In that proceeding, Enbridge Gas committed to report upon its progress in implementing the recommendations set out in the Report on UFG in its 2022 Rates filing. In response to that commitment, Enbridge Gas filed a UFG Progress Report in its 2022 Rate Application. However, the OEB determined that the issues relating to UFG were out of scope for that proceeding and that the UFG Progress Report and other updates as it relates to the implementation of recommendations from the 2019 Report on UFG would be considered as part of the 2024 Rebasing proceeding.

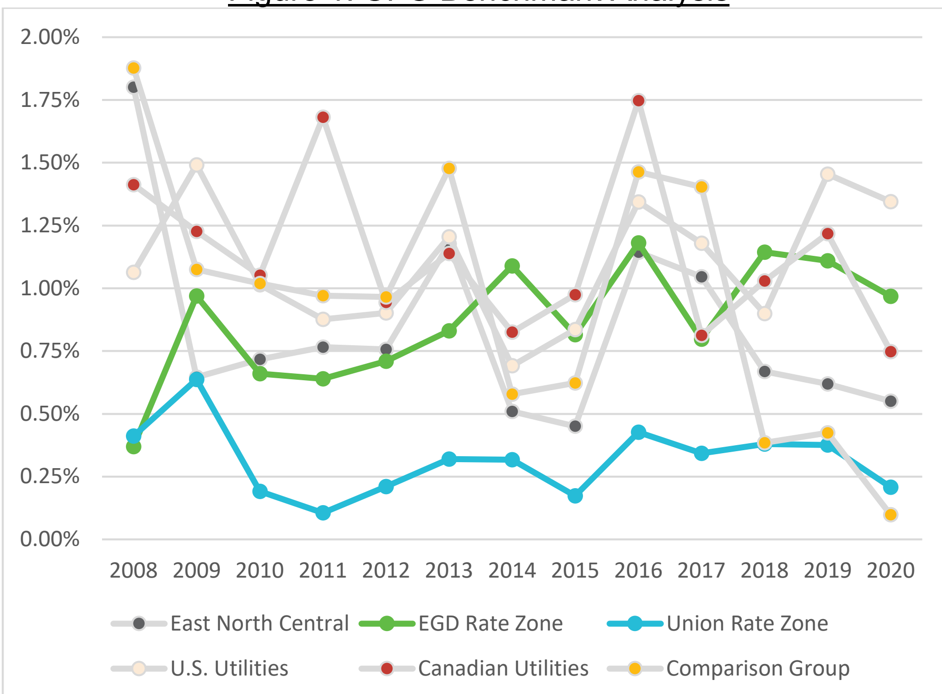
6. In accordance with the OEB direction, the UFG Progress Report, as originally filed in the 2022 Rates Application, has been provided at Exhibit 4, Tab 3, Schedule 1, Attachment 3. This supplemental progress report is intended to provide updates that have occurred since the filing of the initial UFG Progress Report.

2. Benchmarking Analysis

7. The 2019 Report on UFG included benchmarking analysis that demonstrated that UFG, as a percentage of throughput for Enbridge Gas in both the EGD and Union rate zones, was lower than its peers. Enbridge Gas has collected the most current publicly available data for the same peer group included in the benchmarking analysis from the 2019 Report on UFG. The benchmarking analysis from the Report on UFG has been updated with data up to and including 2020 and is provided in Figure 1.

[6] EB-2019-0194.

Figure 1: UFG Benchmark Analysis



8. Based on the data in Figure 1, Enbridge Gas, in both the EGD and Union rate zones, continues to demonstrate lower UFG levels than comparative gas utilities. Figure 1 shows that the EGD and Union rate zones have an average UFG level of 0.87% and 0.32% of throughput, respectively, from 2008 to 2020. During the same period, U.S. gas utilities have an average UFG level of 1.10%, select Canadian gas utilities have an average UFG level of 1.10%, regional U.S. gas utilities have an average UFG level of 0.83%, and a "Comparison" group of gas utilities have an average UFG level of 0.95% of gas receipts.

3. Updates on UFG by Source

9. As part of its research and analysis for the Report on UFG, ScottMadden identified certain common sources of UFG across the industry, including physical losses (e.g.

leaks, third-party damage and venting during construction and maintenance activities), metering variations, non-registering meters, theft, linepack and billing and accounting adjustments.

10. In the Report on UFG, ScottMadden also provided a number of recommendations as follows:
    a) Identify and standardize “best practices” across the legacy Companies;
    b) Document data, process and studies related to monitoring and managing UFG; and
    c) Investigate the sources of UFG, research industry practices and initiatives for monitoring and managing sources of UFG, and implement, as appropriate, new practices and initiatives to better monitor and manage sources of UFG.

11. The following sections provide updated data relating to the individual sources of UFG, as well as updates on the implementation of the recommendations noted above that are incremental to those in the UFG Progress Report provided at Exhibit 4, Tab 3, Schedule 1, Attachment 3.

3.1. Physical Losses

12. Physical losses are a source of UFG at Enbridge Gas. Contributors to physical losses include leaks and emissions from natural gas facilities, releases of natural gas during maintenance, construction and emergency situations, and line hits due to third-party construction or excavation activities.

13. Enbridge Gas reports fugitive, vented and flared emissions annually to Environment and Climate Change Canada and the Ontario Ministry of Environment, Conservation and Parks. Figure 2 shows a 13% decline in emissions and leaks

within the consolidated Enbridge Gas operations from 2015 to 2021. Figure 2 shows lost gas from leaks and emissions on a combined basis for Enbridge Gas, while Figure 3 provides a breakdown of the total leaks and emissions for Enbridge Gas by type.

Figure 2: Lost Gas from Leaks and Emissions (10^6m^3)

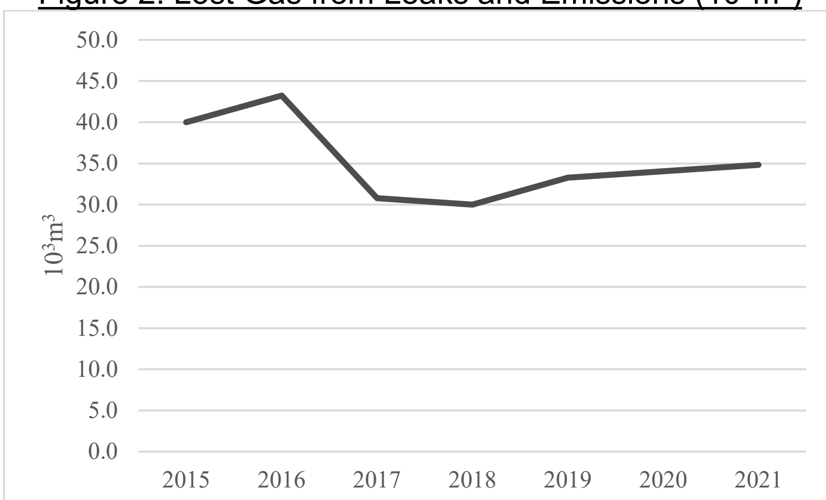
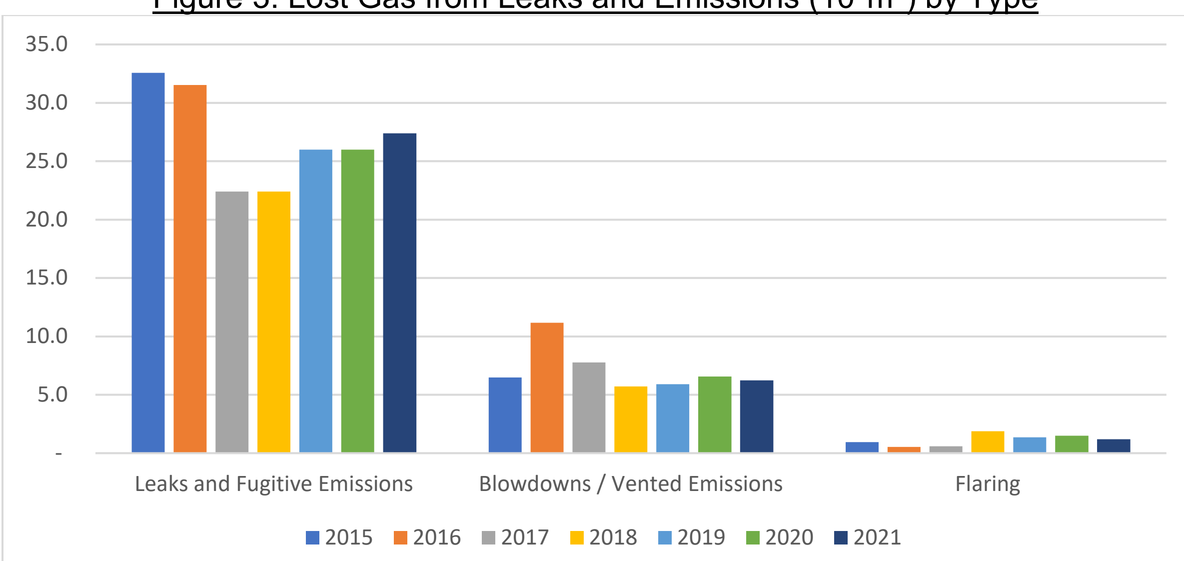


Figure 3: Lost Gas from Leaks and Emissions (10^6m^3) by Type



14. Enbridge Gas has undertaken efforts to reduce physical losses and emissions from its operations. Scope 1 GHG emissions result from Enbridge Gas's operations, and scope 2 emissions result from off-site generation of electricity, which Enbridge Gas buys and consumes. A reduction of scope 1 GHG emissions would indirectly impact the level of UFG experienced within Enbridge Gas's operations.

15. Enbridge Gas has committed to reducing GHGs from Company facilities. To support achievement of the federal and provincial GHG emission targets, as well as the Enbridge GHG reduction targets provided at Exhibit 1, Tab 10, Schedule 3, Enbridge Gas is developing and implementing a scope 1 and 2 GHG emission reduction strategy. Details are provided at Exhibit 1, Tab 10, Schedule 8.

3.2. Retail Meter Variations

16. Retail meter variations represent variations between actual and metered volumes at customer locations. These variations can be attributed to factors including inherent measurement uncertainties of meters, meter failure, inaccurate corrections for temperature and pressure variations or improperly sized meters. Enbridge Gas conducts meter testing on a sample of diaphragm meters annually. These tests are conducted under low-flow and high-flow conditions. Historical test results from 2014 to 2021 are shown in Figure 4 and 5.

Figure 4: EGD Rate Zone Meter Test Results vs Measurement Canada (MC) Standard

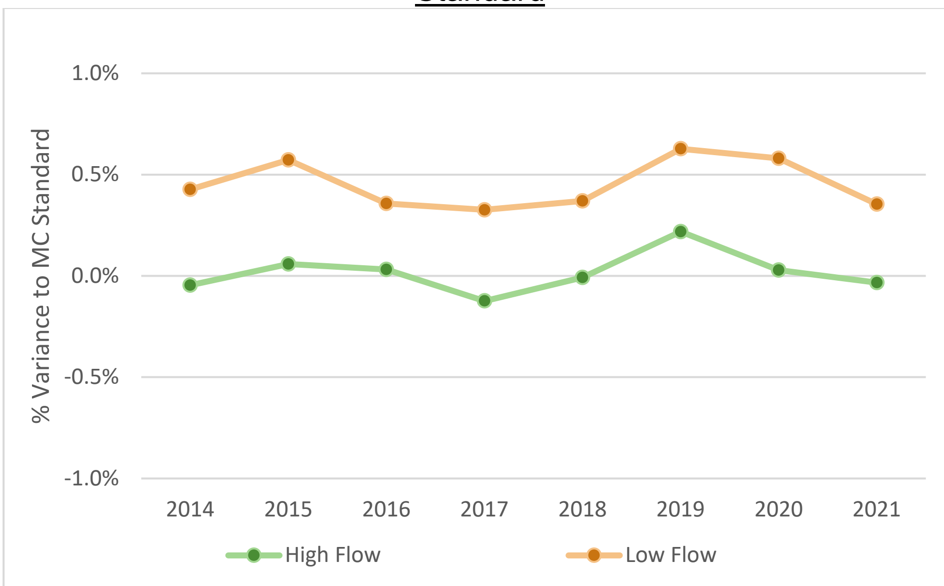
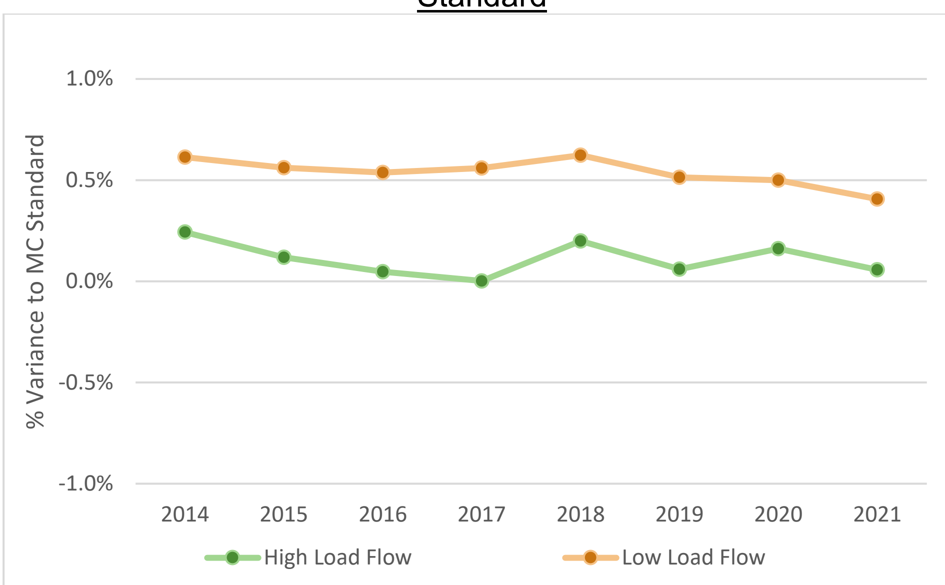


Figure 5: Union Rate Zone Meter Test Results vs Measurement Canada (MC) Standard



17. The variances to the Measurement Canada standard are within the Measurement Canada tolerance of +/- 3.0%. Meters whose test results that fall outside of the +/- 3.0% tolerance are taken out of service. All rotary turbine, and ultrasonic meters are tested on a frequency which is prescribed by Measurement Canada.

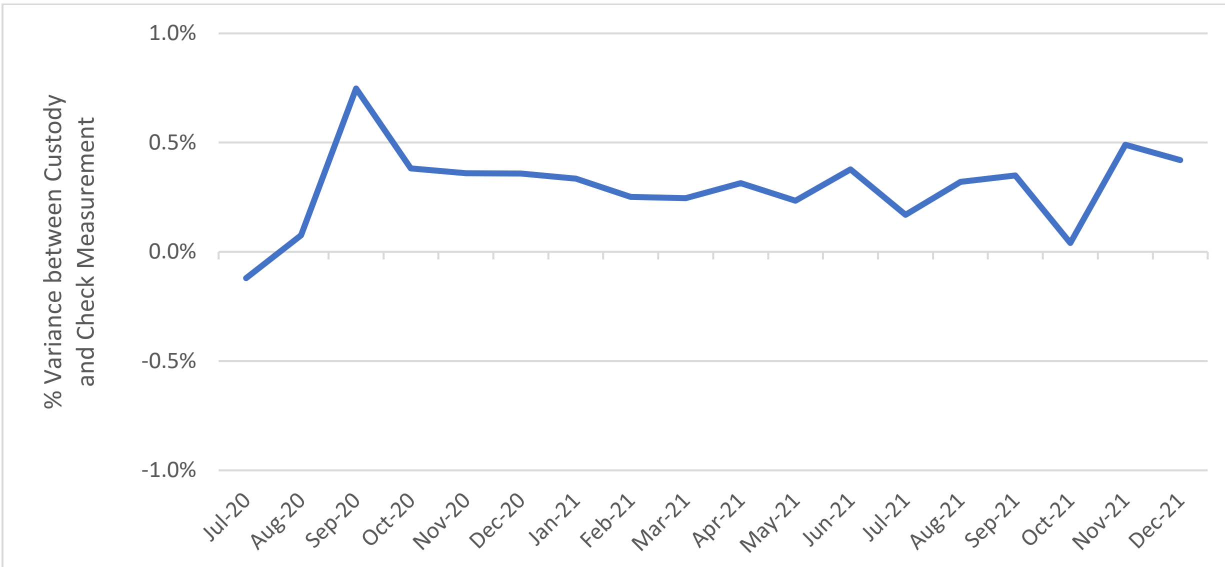
18. In 2022, Enbridge Gas has undertaken an initiative to align the applications utilized for large volume customer meter measurement and ensure consistent volume measurement data validation for large volume customer meter measurement.

3.3. Gate Station Meter Variations

19. Gate station meter variations represent a potential source of UFG if there are differences at receipt points between actual and metered volumes. However, not all gate station meter variations can be wholly attributable to UFG, as the variations may only represent differences in meters, and may not represent actual lost gas.

20. Enbridge Gas utilizes check meters to validate the accuracy of the custody or supplier meters. A comparison between Enbridge Gas's check meters and third-party custody transfer meters is depicted in Figure 6. This figure demonstrates that Enbridge Gas's check measurement falls within the Measurement Canada prescribed range of +/- 3% and with the +/- 2% tolerance of the Enbridge Gas internal benchmark.

Figure 6: Third-Party Custody Transfer vs. Enbridge Gas Check Meters Differences



21. In 2022, Enbridge Gas installed a new Measurement Canada certified remote terminal unit (RTU) at the Gatineau interconnect, which ensured that both custody and check measurement is in place, whereas only one source of measurement was previously available. This also enabled an increased level of data validation by the team accountable for gate station measurement.

3.4. Other Sources of UFG

22. The remaining primary contributors of UFG at Enbridge Gas include theft and non-registering meters, company use, and accounting adjustments. Theft and non-registering meters account for volumes that are not metered or recorded due to unauthorized use or faulty equipment. Company use contributor represents the portion of company use volumes used by Enbridge Gas that are not metered and/or recorded. Accounting adjustments represent variations between actual and reported volumes due to various accounting adjustments, including unbilled sales estimates, billing adjustments, linepack and other accounting related adjustments.

23. In 2022, Enbridge Gas initiated a system application change to refine the reporting underpinning a portion of the unbilled sales estimates recorded at the end of every reporting period for financial accounting purposes. The intended outcome of the change is to improve the accuracy of the estimate, which would help to minimize variances that are temporary in nature associated with the estimate of unbilled volumes.

OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS OVERVIEW

COLIN HEALEY, DIRECTOR FINANCIAL PLANNING & ANALYSIS

1. The purpose of this evidence is to present an overview of operating and maintenance (O&M) costs for EGD, Union and Enbridge Gas from the last rebasing year of 2013 to the 2024 Test Year. This overview will outline the primary cost drivers impacting historical years, along with expected drivers and trends that support the 2024 Test Year O&M amount proposed for recovery.

2. Details of the historical years, 2022 Estimate, 2023 Bridge Year and 2024 Test Year are found in supporting exhibits. Exhibit 4, Tab 4, Schedule 2 provides cost drivers of material variances from 2018 to the 2024 Test Year for each operating department and other non-departmental O&M cost groupings, including impacts from integration costs, synergy savings and productivity savings. Exhibit 4, Tab 4, Schedule 3 provides specific program delivery costs as identified in the OEB's Filing Requirements for Natural Gas Utilities including benchmarking studies for compensation, pension and benefit programs and comparative analysis for the Central Functions Cost Allocation Methodology (CFCAM). In addition, cost benchmarking is provided at Exhibit 10, Tab 1, Schedule 1 and details on integration costs and synergy savings are provided at Exhibit 1, Tab 9, Schedule 1.

3. This evidence is organized as follows:
    1. Background
    2. Overview of Utility O&M
    3. Summary

1. Background

4. O&M costs represent the costs required to carry out typical utility operations. They include salaries and wages, contract services, materials and supplies, rents and leases, and employee-related costs. O&M is distinct from capital costs which are incurred to construct and upgrade property, equipment, and technological assets.

5. A portion of indirect O&M expense is treated as overhead capital to ensure all costs associated with the creation of capital assets are captured as part of the asset cost. Capitalized overhead is excluded from O&M and is quantified through an allocation methodology consistent with accounting standards and the OEB's Uniform System of Accounts. For information on the harmonized overhead capitalization methodology, please see Exhibit 2, Tab 4, Schedule 2.

6. A portion of O&M expense is recognized as supporting unregulated storage functions. The allocation of costs to unregulated storage operations follows a harmonized methodology provided at Exhibit 1, Tab 13, Schedule 2.

7. In this evidence, O&M is expressed after overhead capitalization and unregulated storage allocations are removed. The term utility O&M is used to refer to post-capitalization O&M expenses for regulated utility operations.

2. Overview of Utility O&M

8. This section will outline the primary cost drivers of historical years, along with expected drivers, integration synergies and productivity initiatives impacting the 2024 Test Year Forecast. Also included in this section are overall trend metrics for O&M per customer and per kilometer of plant (pipeline). Table 1 provides a summary of historical and forecast utility O&M.

Table 1
Utility O&M

Line No	Particulars ($ millions)	Utility	Utility O&M	Utility O&M excl. DSM	% Change	/u
			(a)	(b)	(c)	
1	2013 OEB-Approved Budget	EGD/Union	798	735		/u
2	2013 Actual	EGD/Union	792	729		/u
3	2014 Actual	EGD/Union	788	724	(0.6%)	/u
4	2015 Actual	EGD/Union	814	747	3.1%	/u
5	2016 Actual	EGD/Union	848	734	(1.7%)	/u
6	2017 Actual	EGD/Union	845	724	(1.4%)	/u
7	2018 Actual	EGD/Union	883	753	4.1%	/u
8	2019 Actual	EGI	915	785	4.3%	/u
9	2020 Actual	EGI	948	816	3.9%	/u
10	2021 Actual	EGI	921	788	(3.4%)	/u
11	2022 Estimate	EGI	964	832	5.5%	/u
12	2023 Bridge	EGI	1,022	854	2.7%	/u
13	2024 Test Year	EGI	1,046	871	1.9%	/u

9. While there were fluctuations from 2013 to 2018, O&M excluding Demand Side /u
Management (DSM) increased by only 0.7% annually on average. From 2019 to /u
2021, O&M costs excluding DSM increased annually by an average of 1.6%. In /u
these early years of amalgamation, Enbridge Gas was able to achieve synergy savings largely through organization restructuring in 2019 and the Voluntary Workforce Options (VWO) Program in 2020. The VWO Program was offered to provide employees incentive to retire early, take leave, pursue part-time or job-sharing arrangements, or voluntarily exit. More information on the synergy savings is provided at Exhibit 1, Tab 9, Schedule 1. COVID-19 had a substantial influence on the Company's operations and costs during this period and beyond. COVID-19 restrictions led to a reduction in work volume from access limitations and staff availability creating a backlog that will need to be addressed as the Company returns to normal operating conditions in 2022.

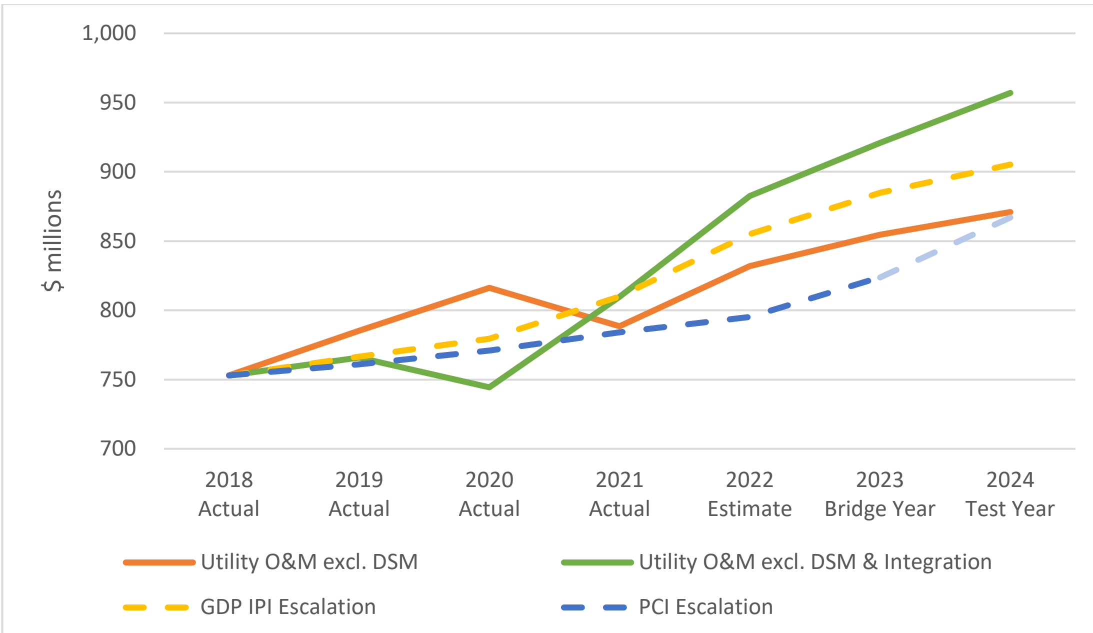
10. In 2022, costs are expected to be higher as the Company returns to normal operations with the elimination of pandemic restrictions, significant inflation, increased compliance requirements, and emerging safety and reliability pressures. Additional internal staffing and contractor resources will be needed to address workload backlogs and the impact of Bill 93, the Getting Ontario Connected Act, 2022, on the costs of locates. Inflation is affecting fuel, postage, labour, third-party contract and materials and supply costs. Other increases are being driven by higher bad debt from economic conditions, prolonged higher commodity prices and inflation. Integrity programs and planned inspections (indicated by the Company's risk tolerance models), and technology industry trends such as the shift to 'as a service' models for technology reliability, business capability and cyber security concerns are also increasing costs. These cost pressures are forecast to push Enbridge Gas's 2022 Estimate 5.5% higher than the 2021 actual, excluding DSM, /u
which is in line with the 2022 GDP IPI forecast of 5.55% (please see the Economic /u
Outlook at Exhibit 3, Tab 2, Schedule 4, Table 1, note 1).

11. In 2023, the Company is expecting cost pressures from inflation, pension costs /u
based on actuarial valuations and locates costs from the implementation of Bill 93. Expanded integrity programs associated with safety and reliability, sustainment costs associated with harmonized systems, and additional resources to support compliance, growth and capital execution initiatives will add additional costs. At the same time, these cost pressures will be mitigated by winding down integration work, the accumulation of integration synergy and productivity savings and the Company's commitment to additional embedded productivity measures (please see Exhibit 4, Tab 4, Schedule 2, Section 1 for more information). As a result, 2023 Bridge Year costs are only expected to increase 2.7% over the 2022 Estimate, excluding DSM, which is lower than the 2023 GDP IPI forecast of 3.5%. /u

12. 2024 Test Year O&M costs, excluding DSM, are expected to be 1.9% higher than the 2023 Bridge Year. The increase is driven by bad debt resulting from higher arrears due to the prolonged impact of higher commodity prices, inflation and adverse economic conditions facing customers. Cost pressures also result from integrity programs required to maintain safety and reliability, increased locate costs from impacts of Bill 93, the shift to 'as a service' models that drive technology reliability, business capability and greater cyber security. In addition, as a cost-of-service Test Year, 2024 O&M includes costs previously subject to deferral and variance account treatment during the deferred rebasing term. For the 2024 Test Year, integration synergies and productivity initiatives, including embedded productivity, will deliver over $121 million of savings to customers. /u

13. Over the deferred rebasing term, integration and effective cost management efforts have resulted in an annual average increase in utility O&M, excluding DSM, of only 2.5%. The effect of these efforts is shown in Figure 1 which demonstrates the benefits of amalgamation and that utility O&M's rate of increase is below inflation. /u

Figure 1: Utility O&M Trend Analysis /u



14. Figure 1 provides a trend analysis by comparing 2018 to 2024 utility O&M excluding DSM (orange line) from Table 1 to: 1) utility O&M excluding DSM, integration initiative costs and synergy savings (green line), 2) 2018 pre-amalgamation utility O&M escalated by GDP IPI (yellow line) and 3) 2018 pre-amalgamation utility O&M escalated annually by PCI[1] (blue line). Please see the Economic Outlook at Exhibit 3, Tab 2, Schedule 4, Table 1 for GDP IPI historical values and future projections[2]. /u

15. Utility integration resulted in significant benefits for customers. Had EGD and Union not integrated and generated synergy savings, as represented by the green line in Figure 1, utility O&M would have initially been lower than actuals in 2019 and 2020

[1] Assumes the continuation of the deferred rebasing term's price cap formula where 2024 PCI is 5.25% (2022 GDP IPI of 5.55% less stretch factor of 0.3%).
[2] GDP IPI escalation in Figure 1 uses updated 2022 GDP IPI projection of 5.55% and updated 2023 and 2024 CPI (as a proxy for GDP IPI) of 3.5% and 2.3%, respectively.

largely because of early integration costs, including severance from 2019 restructuring and 2020 VWO. However, in 2021, as synergy savings accumulated and integration costs began to wind down, the benefits of amalgamation become larger as depicted by the distance between the orange and green lines. From 2022 to 2024, even with the cost pressures expected from rising inflation and impacts of COVID-19, the absence of integration synergy savings would result in $86 million higher utility O&M by the 2024 Test Year. Instead, with integration activities complete and synergies fully realized, the Company will pass on the $86 million as savings to customers for the 2024 Test Year (please see Exhibit 1, Tab 9, Schedule 1, Section 2 for further information integration synergies). Together with productivity savings, which do not rely on amalgamation to be achieved, total savings in the 2024 Test Year are projected at over $121 million (please see Exhibit 4, Tab 4, Schedule 2, Section 1 for further information on synergies and productivity).

16. GDP IPI, as a measure of inflation, is a relevant metric to assess the Company's actual cost performance. The GDP IPI inflation scenario (yellow line) in Figure 1 demonstrates the benefits of the Company's integration, cost mitigation and efficiency efforts. From 2021 to 2024, had amalgamation not occurred (green line), utility O&M would exceed GDP IPI derived utility O&M. Significant cost mitigation /u efforts occurred over this period to reduce the inflationary pressures experienced by the Company. Over this same period, actual and forecast utility O&M (orange line) remains below GDP IPI derived utility O&M as synergy and productivity savings accumulate and integration costs wind down. The benefits of amalgamation and /u effective cost management become apparent even as the Company faces significant cost pressures, including rising inflation.

17. Using PCI as a measure of comparison between O&M amounts recovered in rates (blue line) and utility O&M (orange line), Figure 1 demonstrates that Enbridge Gas

has managed cost pressures effectively through integration efforts and productivity. The PCI measure incorporates a two-year lagging inflationary impact, using GDP IPI. Therefore, inflation from one period is not recovered in rates for two years. This lagging effect is demonstrated by a comparison of the blue and yellow lines. Under extraordinary inflationary periods, which has been the case over the last two years, effective cost management has been critical. Prior to 2024, utility O&M exceeded /u PCI escalated utility O&M as the Company undertook integration efforts. Even as cost pressures persist, synergy and productivity savings are mitigating the impacts and bring 2024 utility O&M in line with 2024 PCI escalated utility O&M. /u

18. In addition to pursuing integration initiatives over the deferred rebasing term, Enbridge Gas continues expanding utility services as measured by customers and total plant. Table 2 shows O&M relative to these two measures of growth.

Table 2
O&M Metrics

Line No.	Particulars	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	
	($)								
1	O&M per Customer	EGI	246	252	242	251	264	267	/u
2	O&M per km of Total Plant (1)	EGI	6,091	6,264	6,030	6,262	6,583	6,683	/u
	(% Change)								
3	O&M per Customer	EGI	2.3%	2.6%	(3.9%)	3.6%	4.9%	1.4%	/u
4	O&M per km of Total Plant	EGI	3.0%	2.8%	(3.7%)	3.8%	5.1%	1.5%	/u

Note:
(1) Plant refers to distribution mains and services and transmission mains.

19. From 2019 to 2021, customer growth and total plant growth outpaced O&M, leading to a reduction in O&M per customer and O&M per kilometre of total plant. This period coincided with key restructuring initiatives that drove synergies through reduced FTEs as well as productivity savings. The pandemic also led to restrictions on travel, training, and caused work to be deferred. Overall, growth was carried out with lower costs on a per unit basis. From 2022 to 2024, the pace of customer additions, which impacts total plant, is expected to slow because of economic conditions as provided at Exhibit 3, Tab 2, Schedule 6. Economic conditions are also expected to contribute to O&M cost increases with rising inflationary pressures having an impact on internal and external resource costs and bad debt. Furthermore, the Company is expecting to experience cost pressures in areas not directly correlated to customer and total plant metrics such as work backlog caused by COVID-19, impacts from Bill 93, integrity programs addressing safety and reliability, pension cost fluctuations based on actuarial valuations, costs previously /u

subject to deferral and variance account treatment, technology reliability and cyber security. Despite these pressures, from 2019 to 2024, synergy and productivity savings have maintained utility O&M costs to an average annual increase of 2.7%. /u
As a result, average annual increases in per customer and per kilometer of total plant have been maintained at less than 2%. /u

20. Enbridge Gas remains committed to the service quality requirements (SQRs) stipulated by the OEB. It continues to consistently exceed the standards for gas emergency response, reconnection response time, customer complaint written response, and service appointments response time. As provided at Exhibit 1, Tab 7, Schedule 1, Attachment 1, starting in 2020, certain performance measures have not achieved the threshold amounts: a) telephone answering performance dropped to 64.3% in 2021, below the 75% standard; b) call abandon rate increased to 16% in 2021, above the 10% requirement; and c) meter reading performance increased to 4.4% and 5% in 2020 and 2021 respectively, above the 0.5% threshold of the number of meters unread for four consecutive months. Call answering and call abandon rates were affected by the Customer Information System (CIS) consolidation project which migrated 1.6 million customers to the new system at the same time that the Interactive Voice Response (IVR) automated system was put in place. In addition to staffing challenges as a result of pandemic impacts, IVR and digital adoption also enabled self-service on issues that were relatively easy to resolve, leaving more complex issues to be handled through calls. This increased the time needed to resolve issues and affected call performance. Similarly, meter readings were affected by staffing and access considerations during the pandemic. As provided at Exhibit 1, Tab 7, Schedule 1, the Company is continuing to work diligently to implement its mitigation plans to improve performance in these areas and in areas where challenges may persist, the Company has proposed certain modified performance measures for the OEB's consideration.

3. Summary

21. Enbridge Gas's O&M costs, excluding DSM, are projected to grow at a rate of 2.5% from 2018 to the 2024 Test Year. Inflation, as measured by GDP IPI, is projected to grow at a rate of 3.1% during that same period, demonstrating the Company's effective cost management practices. The Cost Benchmarking Analysis prepared by Black and Veatch, provided at Exhibit 10, Tab 1, Schedule 1, Attachment 1, also demonstrates that Enbridge Gas is a good cost performer relative to its peers, with an O&M cost per customer well below the utilities measured. The Company's focus on driving integration synergies and productivity savings as well as effective cost management have resulted in lower costs than if EGD and Union had not amalgamated. The Company has been able to mitigate the impact of significant inflation and cost pressures. Through this period, the Company also had to manage the global pandemic and the resulting provincial restrictions which delayed the completion of work and led to resourcing challenges, in both labour and materials. Throughout the deferred rebasing term, the Company continued to support customer growth and maintained its commitment to safety, reliability, and customer service. /u

SUMMARY AND COST DRIVERS

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1. This evidence presents operating and maintenance (O&M) expenses with cost drivers of material variances for the 2018 to 2021 historical years as well as the 2022 Estimate, 2023 Bridge Year and 2024 Test Year Forecast. This evidence also requests OEB approval of the 2024 Test Year O&M Forecast.

2. This Exhibit supports the O&M overview provided at Exhibit 4, Tab 4, Schedule 1 which demonstrated that Enbridge Gas's historical and projected O&M is below inflationary trends since the last rebasing year and from 2018 to the 2024 Test Year. Additionally, the Company has balanced rising costs with efficiencies and synergies through integration to support customer growth and maintain its commitment to safety, reliability, and customer service. The benefits of integration have been passed on to customers as part of the restatement of baseline costs for the 2024 Test Year. Exhibit 4, Tab 4, Schedule 3 provides specific program delivery costs as identified in the OEB's Filing Requirements for Natural Gas Utilities as well as central functions (CF) costs and drivers.

3. Enbridge Gas's O&M expense is comprised of the costs to carry out the required business activities for each department along with those business activities provided by CF for Enbridge Gas. As noted in the Utility System Plan at Exhibit 2, Tab 6, Schedule 1, O&M budgets assessed all cost areas. Where detailed cost inputs or drivers were known or available, they were reflected in the estimate. Where detailed cost inputs or drivers were not available, inflation adjustments were

layered onto historical amounts. Inflation as measured by Canadian CPI is forecast to be 2.4% for 2023 and 2.2% for 2024. Economic assumptions are provided at Exhibit 3, Tab 2, Schedule 4[1]. The 2024 Test Year Forecast was developed with Enbridge Gas's key business objectives in mind, ensuring continued focus on safety and reliability under existing regulatory, environmental, and legislative requirements, while preserving the operational efficiencies gained from integration and alignment.

4. This Exhibit presents a breakdown of O&M costs by operating department and expense category, along with driver analysis of cost variances, for which consistent analysis can only be carried out starting in 2018.

5. The evidence is organized as follows:
    1. Overview
    2. Business Development & Regulatory (BD&R)
    3. Customer Care
    4. Distribution Operations (Operations)
    5. Energy Services (ES)
    6. Engineering and Storage & Transmission Operations (Engineering & STO)
    7. Central Functions (CF)
    8. Business Unit (BU) Benefits
    9. Integration-Related Costs
    10. Capitalized Overhead Costs
    11. Utility O&M

[1] The 2022 to 2024 forecasts were developed based on assumptions available at Q1 2022. The forecasts have not been adjusted to reflect the changes in inflation that have occurred since Q1 2022.

6. Section 1 provides an overview of the primary cost drivers and trends impacting the 2022 Estimate, 2023 Bridge Year and 2024 Test Year, including integration synergies and productivity savings. Sections 2 to 7 cover operating departments including descriptions of operational structure, historical variance analysis with reference to integration efforts and synergies achieved, productivity savings, and the cost drivers for the 2022 Estimate, 2023 Bridge Year, and 2024 Test Year amounts. Sections 7 to 10 cover cost areas that warrant presentation separate from or not directly attributable to operating departments. The evidence concludes in Section 11 with a summary of utility O&M for the 2024 Test Year and cost driver tables.

1. Overview

7. Table 1 shows utility O&M from 2018 to the 2024 Test Year. Lines 1 to 7, along with associated detailed tables provided in Sections 2 to 7, provide gross utility O&M so that described variances are directly aligned with cost drivers. Cost savings from synergy initiatives and productivity are reflected in utility O&M and discussed later in this section. Overhead capitalization at line 8, reflects the proposed harmonized overhead capitalization methodology in effect since 2020 as provided at Exhibit 2, Tab 4, Schedule 2. Unregulated storage allocations have been reflected in Table 1 and tables in the subsequent sections as the focus of this Exhibit is on utility O&M. The unregulated storage allocation methodology was harmonized and is proposed to be implemented in 2024 as provided at Exhibit 1, Tab 13, Schedule 2.

Table 1
Utility O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual (1)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Business Development & Regulatory	EGI	43	37	28	33	35	40	47	
2	Customer Care	EGI	153	131	118	117	118	124	135	
3	Distribution Operations	EGI	275	281	268	274	309	331	338	
4	Energy Services	EGI	21	17	14	16	17	19	18	
5	Engineering & STO	EGI	113	110	96	111	146	158	155	/u
6	Central Functions	EGI	231	237	245	280	337	353	377	/u
7	BU Benefits	EGI	144	158	148	143	104	112	111	/u
8	Overhead Capitalization	EGI	(227)	(237)	(224)	(234)	(269)	(301)	(310)	
9	Utility O&M excl. Integration and DSM	EGI	753	734	692	739	797	835	871	/u
10	Integration-Related Costs	EGI	0	52	124	50	35	20	0	
11	DSM	EGI	130	129	132	132	132	167	175	/u
12	Utility O&M	EGI	883	915	948	921	964	1,022	1,046	/u

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

8. Integration synergies and productivity resulted in declining utility O&M excluding integration-related costs and Demand Side Management (DSM) (line 11) from 2018 to 2020. In addition to the reductions tied to amalgamating EGD and Union, in 2020, COVID-19 resulted in a significant curtailment of work as provincial restrictions limited site and asset access. In addition, travel was limited due to reduced work volumes and provincial restrictions and labour shortages were driven by worker and contractor illness. In 2021, as restrictions lifted, work volume started to increase slowly as the company was still dealing with staff shortages due to attrition, turnover and illness and material supply issues. Utility O&M costs increased in 2021 due to a gradual ramp up in work volume as well as inflationary pressures.

9. Utility O&M costs for the 2022 Estimate, 2023 Bridge Year and 2024 Test Year are being driven by several key trends. Most notably, COVID-19 and resulting restrictions led to a reduction in work volume. The result was deferral of work, creating a backlog that will need to be addressed as the Company returns to normal operating conditions in 2022. Significant inflation and labour market challenges, including shortages and contractor cost pressures, are broader outcomes of COVID-19 that are expected to persist. Other trends and factors impacting costs include legislative impacts on locates, cyber security threats to the energy industry, changes in the technology industry and global insurance market, bad debt and amounts previously subject to deferral and variance account[2] treatment now included in utility O&M for recovery in rates. Mitigating these pressures are pension

[2] Accounts impacted are 1) OEB Cost Assessment Variance Account (OEBCAVA), 2) Greenhouse Gas Emissions Administration Deferral Accounts (GHGEADA), and 3) IRP Operating Costs Deferral Account (IPROCDA).

valuations and the productivity and synergies resulting from the amalgamation of EGD and Union. Without these efficiencies, O&M costs would have been higher.

10. Beginning in 2022, impacts of COVID-19 become a significant driver of costs. Increased levels of internal staffing and contractor resources are forecast to increase costs in 2022 as Distribution Operations (Operations) returns to pre-COVID-19 volumes of work while continuing to address the backlog of deferred work. Significant levels of inflation affecting fuel, postage, labour costs, and third-party contract costs are projected to push costs beyond the levels experienced post amalgamation. Additionally, internal staffing and contractor resources will be critical as the Company (1) continues to expand the distribution system in response to requests for customer additions, (2) ensures safety and reliability through integrity programs informed by risk modelling, including cross bore inspections, and (3) meets compliance obligations such as Bill 93 (the Getting Ontario Connected Act, 2022), which affects locates costs. Technology & Information Services (TIS) costs are under pressure as the technology industry moves to 'as a service' for infrastructure and software necessitating a shift from capital costs to O&M, along with additional investment in cyber security as threats to the energy industry increase. Offsetting the impact of these increases are lower benefit costs due to decreasing pension costs, as projected by actuarial valuations.

11. In 2023, bad debt, pension costs and TIS costs related to migration to 'as a service' /u
models to enhance technology reliability and training, change management and sustainment associated with harmonized systems will be a key driver along with drivers mentioned for 2022. Lower integration-related costs as initiatives are closed out will partially alleviate overall cost pressures. The 2023 Bridge Year also reflects /u
the impacts of Enbridge's new insurance strategy which is detailed in Section 4.

12. Several of the key trends noted for the 2022 Estimate and 2023 Bridge Year continue to drive the core components of 2024 Test Year Forecast. These include integrity programs informed by risk modelling, cross bore inspections, increased locate costs from impacts of Bill 93, bad debt, the shift to an ‘as a service’ model and cyber security measures. Another factor increasing O&M in the 2024 Test Year are costs that were subject to deferral and variance account treatment during the deferred rebasing term.

13. Enbridge Gas’s historical and projected O&M is below inflationary trends from 2018 to the 2024 Test Year. Table 1 shows that utility O&M excluding DSM and integration related costs has grown from $753 million, pre-amalgamation in 2018 to a projected $871 million in 2024, an annualized increase of 2.5% per year. /u
Significant cost pressures during this period have been mitigated by integration synergies and productivity savings gained over the deferred rebasing term while maintaining the Company’s commitment to safety, reliability, and customer service.

14. Table 2 shows annual O&M savings resulting from integration synergies and productivity initiatives. The savings achieved have been reflected in the 2024 Test Year.

Table 2
Integration Synergies and Productivity Savings

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

15. Synergies are defined as cost savings that were delivered through integration initiatives under conditions made possible by amalgamation. These synergies include the 2019 initial Enbridge Gas organization restructuring and role rationalization and the 2020 Voluntary Workforce Options (VWO) Program which incentivized employees to retire early, take leave, pursue part-time or job-sharing arrangements, or voluntarily exit. While VWO was an Enbridge initiative in response to COVID-19, its implementation in 2020 led to swifter role rationalization by advancing resourcing reductions that were expected over the amalgamation period leading up to rebasing. The efforts undertaken by Enbridge Gas throughout the deferred rebasing term are expected to deliver $86 million of annual savings that will constitute savings to customers in the 2024 Test Year. Please see Exhibit 1, Tab 9, Schedule 1 for further details on the integration initiatives that drove synergies. Where relevant, the cost driver impact of synergy savings on operating department costs will be referenced in the subsequent sections of this Exhibit.

16. In addition to synergies, other initiatives which did not require integration resulted in productivity savings. Productivity savings have been achieved across all operating areas during the deferred rebasing term. The most significant occurred through higher e-bill adoption which built on an initiative prior to integration. Through

promotion strategies and an improved sign-up process through the web interface, 62% of Enbridge Gas customers are on e-bill. This is recognized to be a best-in-class benchmark which suggests limited take-up beyond the current adoption rate. Other initiatives include Interactive Voice Response (IVR) automation which allows for call reductions by giving customers the ability to self-serve. Emergency call handling was combined with the dispatch function and enabled contractor savings. Land management of contaminated sites was prioritized according to risk, effectively reducing the scope of work. Other savings were achieved in expense areas where services were scaled back or no longer required. Productivity initiatives are expected to deliver $35.2 million in savings for the 2024 Test Year.

17. At this time, opportunities for additional productivity savings have not been identified. However, productivity savings have been embedded to reflect committed savings which the Company will strive to manage. These embedded productivity savings allow the Company to maintain O&M below the level of inflation for the 2024 Test Year (please see Exhibit 4, Tab 4, Schedule 1 for more information). Gross O&M reductions of $20.7 million ($13.9 million net O&M) and $28.5 million ($18.1 million net O&M) have been included in the 2023 Bridge Year and 2024 Test Year, respectively. The net O&M embedded productivity for the 2023 Bridge Year and the 2024 Test Year is included in each year’s productivity savings in Table 2. The 2024 Test Year contains a reduction in salaries & wages of $7 million and other cost categories of $21.5 million, primarily factored into the forecasts for Operations and Engineering & STO. The cost component and departmental breakdown of the embedded productivity amounts are preliminary estimates as the Company has not conclusively identified the additional productivity opportunities.

18. Together, integration synergies and productivity initiatives, including incremental net O&M embedded productivity of $4.2 million in 2024, are expected to deliver $121.2 million of annual savings that will constitute savings to customers in the 2024 Test Year. As a result, the revenue requirement is lower than it otherwise would have been due to the combination of integration synergies, productivity savings and incremental embedded savings. Variance analyses in the subsequent sections are carried out on costs that reflect embedded productivity savings.

2. Business Development & Regulatory (BD&R)

2.1. Mandate and Operational Structure

19. The BD&R department is comprised of five groups: Energy Transition Planning, Business Development, Public Affairs & Ombuds, Regulatory Affairs, and Marketing and Energy Conservation.

20. The Energy Transition Planning (ETP) group centralizes Enbridge Gas's resources and expertise in the areas of climate and carbon issues and integrated resource planning (IRP). The group leads the development of the energy transition plan and oversees the coordination of its associated goals and objectives. This includes leading Enbridge Gas's emissions reduction strategy, leading and coordinating the implementation of IRP, providing insight on climate policies to other departments in the Company and implements carbon pricing policies.

21. The Business Development group is responsible for advancing low-carbon and energy efficient solutions to ensure affordability and resiliency and reduce greenhouse gas (GHG) emission for customers. This ranges from new end-use technologies that are highly energy efficient to innovative new supply and delivery

options including compressed natural gas (CNG), renewable natural gas (RNG) and hydrogen.

22. The Public Affairs and Ombuds (PA&O) group's accountabilities consist of: internal communications, including executive and employee communications; community engagement through community investment and events; internal and external event planning; external communications and media relations; crisis communications; customer communications, including social media accounts and websites; internal and external energy advocacy; municipal, Indigenous and stakeholder engagement; and the Ombuds Office. The Ombuds Office reviews and addresses issues/complaints from customers, including government and regulatory stakeholders.

23. The Regulatory Affairs (Regulatory) group oversees all regulatory proceedings and policy initiatives before the OEB. Such proceedings include annual rate applications, quarterly gas commodity related rate changes, leave-to-construct applications, certificate of public convenience and necessity applications, franchise applications and renewals, storage designation applications, and various generic proceedings. Regulatory works to ensure the Company's business strategies incorporate regulatory considerations and requirements, manages all OEB regulatory proceedings, determines the appropriate allocation of the Company's revenue requirement amongst the rate classes, responsible for Affiliate Relationship Code (ARC) compliance, and is heavily involved in the working relationships with regulators and stakeholders.

24. The Marketing and Energy Conversation group comprises Distribution Marketing and DSM. The Distribution Marketing group is responsible for providing marketing,

market research and data analytics support for the business's core operations, DSM programs, and growth programs which bring new customers to the distribution system. This includes areas such as Customer Care, Operations, Community Expansion, CNG, and RNG. The Marketing group is also responsible for developing and delivering cost effective marketing campaigns tailored to targeted customer segments that create value by promoting safety, new programs and benefits, and efficient use of natural gas.

25. The DSM group manages the administrative and regulatory requirements for the Company's DSM portfolio and ensures that all programs meet cost effectiveness requirements. The Company's multi-year DSM Plan Application[3] was filed with the OEB on May 3, 2021, and is designed to make homes and businesses more energy efficient, help lower average annual gas usage, and help meet Ontario's GHG reduction goals. The expenses incurred by this group are a pass-through component of utility O&M and are included in total recoverable amounts although part of a separate proceeding. DSM programs are reported annually to the OEB as outlined in the DSM Plan Application and corresponding reporting requirements.

2.2. *BD&R Costs – Variance Analysis*

26. Table 3 provides a summary of O&M costs from 2018 with combined EGD and Union actuals through to the 2024 Test Year using the current amalgamated structure to facilitate year-to-year comparability. The cost categories in the particulars column reflect the primary contributors of BD&R's historical actuals, forecasts and associated variance drivers. The other O&M category is comprised of items such as travel and accommodations and materials and supplies. All costs are shown for regulated operations before capitalization is applied.

[3] EB-2021-0002.

Table 3
Business Development & Regulatory O&M

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

Notes:
(1) 2018 reflects combined EGD and Union actuals.
(2) 2018 Other O&M includes $1 million credit for energy conservation which represents EGD's share (50%) of the net recovery generated by providing conservation and demand management (CDM) activities. Ratepayer share (50%) was cleared through the Electric Program Earnings Sharing Deferral Account (EPESDA).

27. Overall, the costs for BD&R increase from $42.6 million in 2018 to $47.2 million in the 2024 Test Year, an annual average increase of 1.7%. Significant O&M reductions due to synergies resulting from restructuring and lower spend due to the impact of COVID-19 in 2019 and 2020 were later offset by the resumption of activity from the easing of COVID-19 restrictions starting in 2021 and carrying into 2022 as well as impacts due to significant inflationary pressures. In addition, the Test Year includes costs recovered in deferral accounts in 2023 and earlier in the amount of $7.1 million.

BD&R – 2019 Actual vs 2018 Actual

28. In 2019, BD&R costs were $5.9 million lower than the pre-amalgamated 2018 actuals. Salaries & wages were reduced by $3.6 million due to the 2019

restructuring that led to a reduction of full-time equivalents (FTEs) in areas where roles were redundant and lower severance as 2019 severance was captured in integration-related costs (please see Section 9 and Exhibit 1, Tab 9, Schedule 1). The $3.9 million decrease in contract services was due to the manner in which rate hearing and regulatory costs are now recognized. These costs are expensed when incurred in alignment with US GAAP.

BD&R – 2020 Actual vs 2019 Actual

29. In 2020, BD&R costs decreased by $8.6 million as compared to 2019. Salaries & wages were $2.1 million lower due to full year effectivity of FTE reductions from the 2019 restructuring and through FTEs who took part in VWO. Contract services cost dropped by $1.7 million in 2020 as a result of lower business development research costs, advertising costs, and intervenor costs from the synergy of operating as a single, amalgamated entity. Sponsorships & memberships decreased by $3.9 million due to limited sponsorship opportunities during COVID-19.

BD&R – 2021 Actual vs 2020 Actual

30. In 2021, BD&R costs increased $4.6 million over the previous year. Contract services accounted for $1.3 million of the increase resulting from consulting studies undertaken in preparation for the rebasing application. Sponsorship costs increased $3.1 million compared to 2020 in response to greater community needs and the ramping up of sponsorship activities with the easing of COVID-19 restrictions.

BD&R – 2022 Estimate vs 2021 Actual

31. 2022 Estimate costs are expected to be $2.2 million higher than 2021. An increase in salaries & wages of $2 million is due to merit, along with FTE additions for distribution marketing to support increased customer base and filling open roles

created by turnover and attrition during COVID-19. Increases in contract services and other O&M spend is primarily due to investigative costs relating to potential capital projects and the resumption of travel, employee training, and normal levels of marketing and public affairs activities. These increases are offset by sponsorships which are forecast to decrease in 2022 following a ramp-up of activities in late 2021. Sponsorships costs fluctuate in response to the timing of community needs and sponsorship opportunities. Sponsorships are expected to return to a more stable level by 2023.

BD&R – 2023 Bridge Year vs 2022 Estimate

32. 2023 Bridge Year costs are expected to be $4.7 million higher than 2022 Estimate. The anticipated $1.3 million increase in contract services is due to OEB hearing and intervenor costs to support the rebasing application. The $2.1 million increase in sponsorships reflects typical annual expenditure based on community needs and opportunities.

BD&R – 2024 Test Year vs 2023 Bridge Year

33. 2024 Test Year costs are expected to be $7.6 million higher than 2023 Bridge Year. A significant portion of this increase is due to costs previously not reflected in rates but recovered through deferral accounts in 2023 (and earlier), which are now included in the 2024 Test Year Forecast under salaries & wages and contract services. The $4.3 million increase in salaries & wages includes $1.8 million in FTE additions for IRP and $1.4 million for administrative staff related to compliance with federal and provincial GHG emission regulations previously recovered through the IRP Operating Costs Deferral Account (IRPOCDA) and the GHG Emissions Administration Deferral Account (GHGEADA). The remaining increase in salaries & wages is due to merit. Contract services is forecast to increase by $3 million which includes $3.9 million for OEB costs previously recovered through the OEB Cost

Assessment Variance Account (OEBCAVA) partially offset by the elimination of $1.5 million in rebasing hearing and intervenor costs from 2023. Please see Exhibit 9, Tab 1, Schedule 1 for more information on deferral and variance accounts. The remaining $0.6 million variance is due to consulting and marketing increases to support energy transition and community expansion projects.

3. Customer Care

3.1. Mandate and Operational Structure

34. The Customer Care department is accountable for the systems and processes that support 3.8 million customers including all aspects of billing, contracting, customer contact and revenue management. The department is also responsible for the overall customer experience of mass market, large business, and industrial customers through the various channels such as the contact centre, web and chatbot. The Customer Care team is focused on meeting customers' evolving needs to promote a positive customer experience. The department is organized into three main groups: Customer Care Operations, Large Volume Contracting & Policy, and Distribution In-Franchise Sales.

35. Customer Care Operations is responsible for handling all mass market customer needs including customer inquiries, meter reading, billing, payment processing and collections. The group works with customers to understand their evolving needs to implement processes and procedures that align with the customer expectations of Enbridge Gas. This group is also responsible for the customer experience through digital channels (My Account, IVR and web chat).

36. Large Volume Contracting & Policy is responsible for managing contracting, customer support, billing, payment processing and supporting policies for large volume customers. This group is also responsible for managing third-party

programs, such as direct purchase, Distributor Consolidated Billing (DCB), and Open Bill Access (OBA).

37. Distribution In-Franchise Sales is responsible for the market relationships with the large volume customers, builders and developers and related associations across Enbridge Gas's franchise area. These activities include customer support, the application of rates and services to determine if customers meet large volume rate class qualifications and the overall commercial and core business development processes for both new customers requesting service and existing customers seeking to increase their demand. The group is also responsible for the establishment of new business policies (customer connections) which includes compliance and reporting requirements related to E.B.O. 188. In addition, this team is responsible for community expansion activities related to sales and community engagement during the initiation and construction phases of each community expansion project.

3.2. *Customer Care Costs – Variance Analysis*

38. Table 4 provides a summary of O&M costs from 2018 with combined EGD and Union actuals through to the 2024 Test Year using the current amalgamated structure to facilitate year-to-year comparability. The cost categories in the Particulars column reflect the primary contributors of Customer Care's historical actuals, forecasts and associated variance drivers. The other O&M category is comprised of items such as travel and accommodations, materials and supplies and memberships. All costs are shown for regulated operations before capitalization is applied.

Table 4
Customer Care O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual (1)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Salaries & Wages	EGI	26.6	24.5	22.1	23.7	24.1	25.6	27.1
2	Contract Services	EGI	106.0	93.3	81.6	82.8	75.9	79.4	80.9
3	Bad Debt	EGI	10.6	9.0	10.7	13.2	14.1	17.5	21.5
4	Other O&M	EGI	9.8	3.9	3.2	(3.1)	4.2	1.4	5.6
5	Total	EGI	153.0	130.7	117.6	116.6	118.3	123.9	135.1

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

39. Customer Care's annual costs are driven by providing service to support customers for all aspects of billing, contracting, customer contact and revenue management. Costs for these services fluctuate based on the number of customers. Enbridge Gas outsources a portion of its Customer Care functions including call centre, back-office exception handling, and collections. Contract costs for these functions are unit-based and have a direct correlation with higher customer counts and resulting call volumes, billing support, meter reads, postage and paper costs. In the deferred rebasing period, Enbridge Gas has enhanced the customer experience through digital adoption by implementing self-serve functionality primarily through the Enbridge Gas website and including IVR prompts in the automated system. By doing so, this allows customers the option to self-serve for simple transactions and for the call centre and back-office teams to focus on more complex calls and transactions.

40. The provision for uncollectible accounts or bad debt, which recognizes that not all billings will be collected due to customer default, is another primary component of the department's costs. The magnitude of Enbridge Gas's receivables is driven by weather, commodity prices and economic factors (inflation, unemployment, etc.). debt expense variability is directly correlated with fluctuating receivables, consumer indebtedness and level of collection efforts to manage the amount of customer write-offs. The Company manages the variability of bad debt expense by applying targeted collections activity to improve collections performance and drive reductions in bad debt expense.

41. Overall, the costs for Customer Care decline from $153 million in 2018 to $135.1 million in the 2024 Test Year, an annual average decrease of 2.1%. Significant O&M reductions were due to synergies and efficiencies resulting from restructuring and CIS integration and digitization. These cost reductions were later partially offset by increased costs for customer support due to inflationary pressures, customer growth and increasing call volumes and increasing bad debt costs associated with economic conditions stemming from COVID-19 and limited collections activity, including disconnections for non-payment.

Customer Care – 2019 Actual vs 2018 Actual

42. Customer Care's 2019 costs were lower by $22.3 million compared to 2018 pre-amalgamation levels. Salaries & wages were lower by $2.1 million from 2019 restructuring and lower severance as 2019 severance was captured in integration-related costs (please see Section 9 and Exhibit 1, Tab 9, Schedule 1). Cost reductions in contract services of $12.7 million were primarily achieved from postage savings enabled by increased eBill adoption. As well, other O&M costs were lower by $5.9 million primarily because of $4.9 million from the Customer Care

and CIS rate smoothing mechanism which ended in 2018. Within the Customer Care and CIS Costs Settlement Agreement and proceeding[4], the OEB approved a Customer Care CIS Rate Smoothing Deferral Account (CCCISRSDA), for 2013 to 2018 to capture the difference between the forecast Customer Care and CIS costs versus the amount to be collected in revenues in each year and minimize the rate impact to customers over the IR term. Lastly, bad debt was lower by $1.6 million from improved collection performance and alignment of processes through consolidation of collection agency vendors.

Customer Care – 2020 Actual vs 2019 Actual

43. In 2020, Customer Care costs further decreased by $13.1 million. The decrease in contract services of $11.7 million was driven by a reduction in postage from eBill adoption and the company-wide alignment of meter reading schedules from monthly to bi-monthly readings. Lower salaries & wages of $2.4 million was achieved mainly from the VWO program and full year effectivity of 2019 restructuring savings. Bad debt increased by $1.7 million over the previous year due to higher arrears as a result of the economic factors impacting customers brought about by COVID-19 conditions.

Customer Care – 2021 Actual vs 2020 Actual

44. In 2021, costs decreased by $1 million as compared to 2020. Salaries & wages costs were higher by $1.6 million from merit and higher overtime from the implementation of the integrated CIS. Contract services increased by $1.2 million due to higher negotiated contract rates with a new meter reading vendor. Bad debt increased by $2.5 million due to higher arrears as a result of higher inflation, consumer indebtedness and unemployment rates brought about by COVID-19

[4] EB-2011-0226.

induced market conditions. Other O&M offset these increases with $5.7 million of unapplied customer payments that resulted from the decommissioning of the Union CIS. Due diligence was performed as part of the decommissioning clean-up process to identify customers and refund payments. The remaining unapplied customer payments were written off and represents accumulation over time. The related receivables balances for which the customer payment could not be matched to were captured as part of historical bad debt expense.

Customer Care – 2022 Estimate vs 2021 Actual

45. The 2022 Estimate is expected to be $1.7 million higher than 2021. The Other O&M increase of $7.3 million is primarily driven by the previous year's reduction from unapplied customer payments. Also contributing, is increased travel and employee training from the lifting of COVID-19 restrictions, and licensing costs for new voice to text technology. Bad debt is also expected to increase due to higher arrears as a result of consumer indebtedness caused by higher inflation and other economic factors as well as larger customer bills due to a colder winter and commodity prices. Lower forecast contract services costs of $6.9 million are driven by $11.7 million of year-over-year savings from the CIS integration which enabled the elimination of a third-party contract to support Union's CIS. These savings are partially offset by $3 million in third-party contract costs driven by higher call volumes based on customer count forecast and inflation pressures on postage and paper costs of $1.8 million.

Customer Care – 2023 Bridge Year vs 2022 Estimate

46. The 2023 Bridge Year is higher than the 2022 Estimate by $5.6 million. The main driver is a $3.5 million increase in contract services from third-party contract costs driven by inflation and higher customer counts. Bad debt is forecast to increase

$3.4 million due to higher arrears as a result of consumer indebtedness caused by the prolonged effect of higher commodity prices, inflation and other economic factors. Salaries & wages increase of $1.5 million is attributable to merit increases and additional FTEs to support increased call volumes and increased growth in contract market accounts. The other O&M decrease of $2.8 million is primarily driven by unapplied customer payments where the Company has exhausted efforts to identify customers and refund payments. The related receivables balances for which the customer payment could not be matched to were captured as part of historical bad debt expense.

Customer Care – 2024 Test Year vs 2023 Bridge Year

47. 2024 Test Year costs are forecast to be $11.2 million higher than 2023 Estimate. The main driver is an increase in bad debt due to higher arrears as a result of the prolonged effect of higher commodity prices, economic conditions, and inflation in addition to higher consumer indebtedness. Also contributing to the increase is salaries & wages of $1.5 million for additional FTEs to support the Company's growing customer base and contract services of $1.5 million for anticipated increases from contract pricing due to contract renewals. Finally, the $4.2 million increase in other O&M costs is driven by $3 million from the previous year's reduction from unapplied customer payments and $1.2 million for the Company's proposal to treat DCB as a utility activity. This is consistent with the treatment at Union prior to amalgamation, and therefore related costs have been included in the 2024 Test Year. Please see Exhibit 8, Tab 3, Schedule 2, for more information on the proposal to harmonize DCB and Direct Purchase Administration Charge (DPAC) charges across all Enbridge Gas service areas.

4. Distribution Operations (Operations)

4.1. *Mandate and Operational Structure*

48. The Operations department at Enbridge Gas is responsible for the safe and reliable delivery of natural gas to approximately 3.8 million customers. The distribution system that serves these customers consists of more than 147,000 km of mains and services and more than 37,000 pressure regulating stations. The department is comprised of seven Regional Operations groups and Operations Services and Governance (OSG). The seven regional groups execute construction, maintenance operations, and pressure regulating station work within their specific geographical areas. OSG provides support services to Distributions Operations, such as work management, customer attachment and fleet management, with a focus on repeatable, consistent, and effective delivery of tasks.

49. The Regional Operations groups cover the majority of Ontario and are divided based on geographical location. The Eastern region is centered in the Ottawa area and extends to Kingston; the Toronto region covers the City of Toronto proper; Greater Toronto Area East region includes York, Durham and Peterborough; Greater Toronto Area West region includes Peel and Halton, Dufferin and Simcoe; Southeast region includes Hamilton, Waterloo, Guelph, Brantford and Niagara; Southwest region includes London, Sarnia, Chatham and Windsor; Northern region is comprised of all operations north of Orillia including centres such as Sudbury, North Bay, Sault Ste. Marie, Thunder Bay and Kenora, along with numerous remote communities. Each region has three teams: Operations, Stations Operations and Construction.

50. Operations maintains the distribution system to ensure that it meets the safety and reliability needs of customers. Responsibilities include monitoring and repairing

leaks, completing routine maintenance of system components, emergency response and repairs for approximately 72,000 calls per year, corrosion mitigation maintenance and providing support for pipeline integrity programs. Operations work can also be driven by external factors including completion of government mandated inspections and exchanges of existing meters, along with executing customer-initiated work such as requests to move service lines.

51. Stations Operations operate and maintain all pressure regulating stations. The team’s responsibilities include preventative maintenance on pressure regulating assets, metering assets, odorization and heating equipment.

52. Construction installs, replaces, relocates and decommissions mains and service pipelines and station assets. Construction’s work is guided by the Asset Management Plan (AMP) and is influenced by factors such as customer attachment growth, municipal relocation requests and asset condition.

53. The OSG group ensures effective performance and process standardization across Operations. OSG’s support services aided in the integration of Operations and ongoing efficiency efforts by reviewing and aligning processes, structures and procedures throughout the province. The following paragraph outlines the groups within OSG and the specific functions performed in support of Operations.

54. Work Management forecasts, plans, schedules, and dispatches work. The group also supports emergency call handling and afterhours dispatch, monitoring and enforcement of infractions and performance reporting and analytics which support OEB Service Quality Requirements (SQR) and key performance indicators (KPIs). Business Systems Support monitor, repair and align various systems and associated processes used within Operations. Damage Prevention manages

programs that protect the distribution system including locates and cross bore inspections, corrosion, and leak monitoring. Operations Governance and Utilization aligns processes and procedures, manages compliance programs and administers contract agreements with key vendors. Attachment Services oversees and directs the logistics for attaching new customers including call centres, project feasibility and completion. Technical Field Services execute the installation, tapping, energization, stopping, abandonment, and purging of assigned pipeline projects. Growth and Expansion Services explore opportunities to expand services to expedite growth and to support transition to sustainable fuel sources. Capital Execution, Construction Services and Contract Strategy administers the processes and procedures related to capital, relationships and contracts with third-party contract vendors as well as monitors and executes the Operations capital portfolio within the AMP. Fleet is responsible for the administration, operation, and maintenance of approximately 2,820 units that travel 28.8 million kms annually.

55. Major Projects manages and executes capital projects for Enbridge Gas, providing functions such as engineering, construction planning, project management and project governance. Since this group is dedicated to capital projects, associated O&M costs are fully capitalized resulting in no impact on utility O&M.

4.2. *Operations Costs – Variance Analysis*

56. Table 5 provides a summary of O&M costs from 2018 with combined EGD and Union actuals through to the 2024 Test Year using the current amalgamated structure to facilitate year-to-year comparability. The cost categories in the particulars column reflect the primary contributors of Operations' historical actuals, forecasts and associated variance drivers. The Other O&M category is comprised of cost items such as third-party plant damage recoveries, Insurance, Travel and

Accommodations along with tracking COVID-19 costs. All costs are shown for regulated operations before capitalization is applied.

Table 5
Distribution Operations O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual (1)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Salaries & Wages	EGI	148.8	146.3	131.4	134.0	147.5	153.0	158.9
2	Contract Services	EGI	89.5	100.0	94.1	95.9	110.0	117.3	118.5
3	Materials & Supplies	EGI	16.7	17.5	17.9	17.9	17.7	16.3	16.6
4	Fleet & Fuel	EGI	16.7	16.3	14.0	19.2	22.1	22.4	22.7
5	Other O&M	EGI	(0.9)	(3.9)	6.4	2.8	5.9	15.9	15.3
6	Major Projects	EGI	4.6	4.4	4.0	3.8	5.8	6.0	6.1
7	Total	EGI	275.4	280.6	267.8	273.6	309.0	330.9	338.1

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

57. Overall, the costs for Operations increase from $275.4 million in 2018 to $338.1 million in the 2024 Test Year, an annual average increase of 3.5%. Significant O&M reductions were due to synergies resulting from restructuring and lower spend due to COVID-19 restrictions. These cost reductions were later offset by increased costs associated with a gradual return to normal work volumes as COVID-19 restrictions were lifted in 2021 and 2022 and the impact of completing the backlog of work stemming from COVID-19. In addition, costs have increased due to compliance with legislative changes regarding locates through the introduction of Bill 93 and significant inflation.

Operations – 2019 Actual vs 2018 Actual

58. Operations' costs increased by $5.2 million in 2019. An increase in contract services of $10.5 million was offset by decreases in salaries & wages of $2.5 million and other O&M of $3 million.

59. The increase in contract services was primarily a result of $5.4 million related to an increase in the volume of locates. As required by law and regulated by Technical Safety Standards Authority (TSSA) and Ontario One Call (OOC), Enbridge Gas must complete locate deliveries once notified. Locate requests are a safety requirement to provide the known location of buried utilities to ensure safe excavations are completed by customers and third parties. Enbridge Gas pays a fee per unit for this service. Locate costs fluctuate as volumes are tied to levels of excavation projects completed by utilities, municipalities, and customers[5]. Contract services was also impacted by the cancellation of the Company's aviation contract resulting in a termination fee of $3.5 million which ultimately resulted in future annual savings of $2.5 million starting in 2020. Additionally, rate increases for Operations' third-party vendors resulted in $1.7 million of the year-over-year variance in contract services.

60. Salaries & wages declined by $2.5 million as the 2019 restructuring resulted in savings of $6.7 million from the reduction of supervisory and administrative roles deemed redundant. Severance costs also led to a year-over-year reduction of $1.8 million as 2019 severance was captured as integration-related costs (please see Section 9 and Exhibit 1, Tab 9, Schedule 1). These savings were offset by a merit increase of $3.7 million, contractual signing bonuses agreed to with unions of $1.3

[5] Occupants of residential and/or private property.

million and higher overtime costs of $0.7 million as employees transitioned to work in the amalgamated environment with lower FTEs.

61. Other O&M decreased $3 million primarily due to lower FTEs in 2019, which resulted in a lower employee-related costs such as training and awards, and travel and accommodation.

Operations – 2020 Actual vs 2019 Actual

62. In 2020, Operations costs decreased by $12.8 million. Reductions of $14.9 million in salaries & wages, $5.9 million in contract services and $2.3 million in fleet & fuel were partially offset by a $10.3 million increase in other O&M. COVID-19 and the resulting restrictions impacted the Operations department significantly throughout 2020 and beyond.

63. The decline of $14.9 million in salaries & wages was a result of several cost reductions. First, a $9.4 million reduction from the elimination of Operations FTEs as a result of the post amalgamation restructuring as well as VWO. Some employees who no longer had full-time operational roles, were offered an opportunity to move to integration-related activities such as the Work & Resource Strategy and Work Management Strategy initiatives (please see Section 9 and Exhibit 1, Tab 9, Schedule 1). Second, a $4.8 million reduction was due to COVID-19 as restrictions resulted in lower overtime pay, turnover and attrition that were not backfilled as well as the deferral of trainee hires due to lower work volumes. Third, a $1.3 million reduction in costs was due to the signing bonus paid to unionized staff in the 2019. Lastly, a $1.1 million reduction was related to the transfer of the warehousing function to Supply Chain (CF) as part of realignment of organizational structure. These cost reductions were partially offset by merit increase.

64. The decrease in contract services costs in 2020 were driven by a number of cost reductions stemming from COVID-19 and efficiencies, partially offset by cost pressures. First, a $4.9 million reduction in locates cost was a result of lower volumes of complex locates while standard customer locates remained stable[6]. The volume of complex locates decreased due to municipality and utility's reduced construction volumes impacted by COVID-19. Second, a $5.9 million year-over-year cost decrease was driven by the cancellation of the aviation contract that took place in 2019, resulting in $2.5 million of savings along with a reduction year-over-year associated with the $3.4 million cancellation fee paid in the prior year. Third, $1.5 million of reduced costs were driven by significant amounts of meter work being put on hold during COVID-19. Meter work that required employees to enter customer homes and businesses to complete inspections, were reduced where possible to ensure employee and customer safety during COVID-19. Similarly, meter locking for non-payment was also put on hold in recognition of the extraordinary impact COVID-19 had on customers' economic situation. In addition, a number of construction projects were deferred as a result of restrictions imposed as a result of COVID-19. Fourth, $0.8 million of warehouse costs were transferred to the Supply Chain department (CF). Offsetting these cost reductions was an unforeseen cost of $4.9 million for remediation work related to pipe fitting material that contained lead. Remediation efforts included removal of the contaminated material and cleaning of vehicles that were contaminated in the process. An

[6] Customer locates refer to locates requested from occupants of residential and/or private property while complex locates refer to multiple addresses.

additional cost pressure of $2.3 million was due to various distribution protection programs including increased cross bore[7] inspections and corrosion work.

65. Fleet & fuel costs decreased by $2.3 million primarily due to the lower cost of fuel and lower fuel usage due to work and travel limitations resulting from COVID-19.

66. The other O&M increase of $10.3 million was due to COVID-19 direct costs. The primary contributor was $4.6 million of increased downtime and stand-by pay from deferred capital project work. Employees could not complete capital project work as planned, resulting in lower labour capitalization and increased labour expense tracked as stand-by and downtime. $3 million was incurred to procure contracted emergency coverage to mitigate the risk of inadequate emergency response resources resulting from COVID-19 turnover, attrition, and illness. This cost ensured that resources were available to respond to emergency work while labour shortages persisted. The remaining balance of $2.7 million relates to janitorial services costs to implement enhanced cleaning protocols, and materials and supplies costs to purchase personal protective equipment for employees and contractors such as gloves, masks and hand sanitizer.

Operations – 2021 Actual vs 2020 Actual

67. In 2021, Operations O&M increased by $5.8 million as compared to 2020. Increases in salaries & wages of $2.6 million, contract services of $1.8 million and fleet & fuel of $5.2 million were offset by a decrease in other O&M of $3.6 million.

[7] Cross bores are gas pipelines that intersect with sewer mains. As a known safety risk, mitigation is achieved through field inspections of municipality sewer and sanitary infrastructure in the vicinity of Enbridge Gas assets. These field inspections are completed to confirm that a cross bore does not exist allowing for work to safely take place on municipal sewer assets.

Overall higher costs in 2021 reflect easing of COVID-19 related restrictions and the early stages of a gradual return to normal operating conditions.

68. Salaries & wages increased due to merit and FTE additions of $3.2 million and $1.4 million due to higher overtime related to a gradual return to pre-COVID-19 work volumes and the start of the completion of deferred work. Also contributing to the increases was a $0.7 million signing bonus related to the contractual agreement with unions and $0.4 million from the transfer of technical training costs from the Engineering department. These cost increases were offset by integration savings of $3.3 million realized within salaries & wages through FTE reductions from initiatives such as the Fleet Strategy, Work & Resource and Work Management Strategy (please see Exhibit 1, Tab 9, Schedule 1).

69. Contract services were also impacted by a gradual return to pre-COVID-19 work volumes. Requests for locates and other distribution protection work such as leak survey returned to pre-COVID-19 levels, resulting in a $3.2 million increase in costs. Cross bore inspections, as identified by integrity modelling[8], increased by $1.9 million. The Work & Resource Strategy aligned the use of Extended Alliance vendors across all regions for specific work resulting in an increase of $2.4 million in contractor costs, however led to savings in salaries & wages (please see Exhibit 1, Tab 9, Schedule 1, Section 2.2). These increases were largely offset by $4.5 million in lower lead remediation, which was predominantly resolved in the prior year, and a $1 million transfer of telematics cost to Engineering.

[8] Integrity modelling refers to a probability model which was developed to identify areas within the franchise territory with highest likelihood of containing cross bores. The results of this model are then used to apply consistent criteria for proactive selection of cross bore inspections.

70. Fleet & fuel costs increased due to the impacts of COVID-19 and rising fuel prices. Supply chain issues led to delays in delivery of purchased vehicles causing 100 existing vehicles to be extended beyond optimum useful life, and COVID-19 safety measures that required employees to travel in separate vehicles resulted in increased vehicle maintenance and vehicle rental costs of $3.4 million. Higher fuel costs also led to an additional increase of $1.9 million.

71. Other O&M costs decreased as the easing of COVID-19 restrictions allowed more work to resume leading to lower downtime and standby pay, along with reduced purchases of COVID-19-related materials and supplies.

Operations – 2022 Estimate vs 2021 Actual

72. The 2022 Estimate is $35.4 million higher than the 2021 actual. This is primarily driven by increases in salaries & wages of $13.5 million, contract services of $14.1 million, fleet & fuel of $2.9 million, other O&M of $3.1 million and major projects of $2 million.

73. The year-over-year change in salaries & wages is due to merit of $4.3 million, with the remaining increase driven by higher FTEs as a result of filling open roles created by turnover and attrition during COVID-19. The incremental FTEs support the transition toward pre-COVID-19 work volumes and address the backlog of deferred work that has accumulated due to the suspension of work and resource shortages in prior years as a result of COVID-19.

74. Contract services cost increased year-over-year by $14.1 million. A significant component of this increase is $6.4 million in locates volumes as the construction industry recovers from COVID-19. Further, Operations is experiencing pressure on contract prices for vendors who perform locates on behalf of Enbridge Gas. This

pressure is related to higher demand for labour to meet pre-COVID-19 work levels in a currently constrained labour market. Further pressure on the cost of locates is driven by the introduction of Bill 93 which was passed into law on April 14, 2022. The new regulations mandate absolute liability compliance for 5 day and 10 day locate deliveries depending on the scope of the excavation project. Prior to Bill 93, all reasonable efforts were made to respond to customer locate requests within five business days as required by law. For complex locates, the Company was able to work with third-party contractors to complete the locates on an agreed upon time frame that was considered reasonable for the locate industry. Bill 93 has caused the Company to onboard additional contractor resources to meet the more stringent completion times which has increased the overall cost of locate deliveries. Operations expects upward pressure on contract prices over the next several years as labour shortages in the industry continue to persist. Another major contributor is a $4.9 million increase attributable to work volumes returning to pre-COVID-19 levels along with the partial completion of 2020 and 2021 deferred work including various construction projects, meter exchanges, inspections and meter lock/unlocks. In 2022, meter related work is returning to normal levels while also requiring extra resources to complete the work deferred over the past two years. Since each year brings additional work, it will take several years before all the deferred work is cleared. Finally, $2.7 million incremental costs are related to higher cross bores as the integrity modelling for cross bores identified the need for increased inspections in 2022.

75. Fleet & fuel costs are expected to increase as Operations continues to experience pressures due to higher fuel costs and usage as workload volume returns to pre-COVID-19 levels.

76. The increase in other O&M is driven by multiple cost pressures along with offsetting decreases. The primary driver of the increase is due to an accounting presentation change that reflects damage recoveries as other revenue instead of as an offset to O&M expense. Although there is no net impact to utility earnings, this adjustment causes a $6.2 million increase to other O&M (please see Exhibit 3, Tab 5, Schedule 1, Section 3). Further, as COVID-19 restrictions have lifted, an increase in travel and employee related expenses of $2.3 million is expected. Offsetting these costs pressures is a decrease of $5.0 million in COVID-19 direct costs. As the impact of COVID-19 subsides, the level COVID-19 direct costs have substantially decreased, and separate cost tracking has been eliminated.

77. The increase in major projects costs is due to the addition of new FTEs to support construction and engineering work, filling of open positions in 2022 as well as merit increases. As mentioned in Section 4.1 of this evidence, the O&M costs of the major projects group are fully capitalized due to the capital focused nature of the group’s work.

Operations – 2023 Bridge Year vs 2022 Estimate

78. The 2023 Bridge Year is forecast to be $21.9 million higher than the 2022 Estimate mainly due to increases in salaries & wages of $5.5 million, contract services of $7.3 million and other O&M of $10 million.

79. The increase in salaries & wages is primarily due to a merit increase of $5.9 million. This increase is partially offset by embedded productivity savings that have been allocated to salaries & wages. These embedded productivity savings are preliminary estimates as the Company has not conclusively identified the additional productivity opportunities that will deliver these savings.

80. Contract services are forecast to increase primarily due to $7.4 million of additional locates cost as a result of pressures from labour market shortages as well as Bill 93[9] legislation. Please see Exhibit 8, Tab 3, Schedule 1, Section 1.8 for more information of the expected unit price pressures on locate delivery costs starting in 2023. Cross bore inspections are also expected to increase $1.2 million as identified by integrity modeling. Finally, inflation on contractor rates is expected to lead to a $2.6 million cost increase. These increases were partially offset by embedded productivity savings, which are preliminary estimates as the Company has not conclusively identified the additional productivity opportunities that will deliver these savings commitments.

81. The forecasted increase in other O&M costs is related to insurance costs. Enbridge Gas participates in the enterprise-wide consolidated insurance program that Enbridge arranges on behalf of its subsidiaries and affiliates. For more details, please see Exhibit 4, Tab 4, Schedule 3, Section 2.6. Changing dynamics in the global insurance market have made it difficult for energy companies, including Enbridge, to maintain consistent levels of coverage at historically comparable premiums. Over the past several years, the insurance market from which Enbridge obtains coverage has experienced changing fundamentals[10] which have generally led to higher prices and less availability of coverage. Enbridge expects that these fundamentals will continue over the long term. In response to current and expected market conditions, and to mitigate the rising costs of insurance, Enbridge has

[9] Bill 93, An Act to amend the Building Broadband Faster Act, 2021 and the Ontario Underground Infrastructure Notification System Act, April 14, 2022. https://www.ola.org/sites/default/files/node-files/bill/document/pdf/2022/2022-04/b093ra_e.pdf

[10] These changing fundamentals include falling investment returns for insurers generally; a lack of long-term profitability for insurers underwriting energy industry risks due to the frequency and severity of losses that exceed premiums; increases in the costs associated with insured events; and insurer reduction of availability of coverage for pipeline infrastructure.

implemented an insurance strategy that focuses on insuring only low-probability, high-severity events. Under this approach, premiums are lower than they otherwise would have been, while deductibles for liability and non-liability insurance have increased from $10 million and $20 million, respectively, to $100 million each.

82. With higher deductibles, events that would previously have been covered under insurance will no longer be covered, and Enbridge Gas will be exposed to increased financial risk from unpredictable uninsured events as a result. With support from its insurance broker, Marsh Inc., Enbridge developed liability insurance loss forecasts (loss curves) to estimate an annual potential cost exposure within the higher deductible. The 2023 Bridge Year Forecast includes $13.4 million in forecasted costs within deductibles, as projected by the loss curves at a 90% confidence level. This amount includes approximately $3 million of annual average costs within deductibles based on the prior deductible for liability insurance.

83. Offsetting this increase in other O&M is a reduction in insurance premiums, which are included in the costs allocated from CFs as described in Section 7. As provided at Exhibit 4, Tab 4, Schedule 3, Table 3, 2023 insurance premiums are forecasted to decrease by approximately $8.5 million (or 54%) compared to 2022. Without the implementation of the new insurance strategy, 2023 insurance premiums would have been approximately $19 million (or 265%) higher compared to current 2023 forecasted premiums. Please see Exhibit 4, Tab 4, Schedule 3, Section 2 for more details on the allocation of insurance premiums.

Operations – 2024 Test Year vs 2023 Bridge Year

84. The 2024 Test Year is forecast to be $7.2 million higher than the 2023 Bridge Year mainly due to increases in salaries & wages of $5.9 million and contract services of

$1.2 million. The increase in salaries & wages is primarily due to a merit increase of $7.7 million. The increase in contract services is primarily due to increased locate costs of $2.9 million and cross bore inspections as identified by integrity modelling of $2.4 million. Embedded productivity savings have been included to offset costs as a commitment to deliver savings to customers. As noted above, these embedded productivity savings are preliminary estimates as the Company has not conclusively identified the additional productivity opportunities that will deliver these savings.

85. The new regulations under Bill 93 are expected to cause significant changes to locate delivery services in Ontario. The 2024 Test Year Forecast includes $58.6 /u million for locate delivery costs. $51.1 million of the costs are for locate delivery /u services provided to customers and locate delivery services required for Enbridge Gas's own operations. $7.5 million of the costs include internal company resources /u that provide administrative support to respond to locate requests. The changes to be implemented under Bill 93 are currently in development given how recently the legislation was implemented. Enbridge Gas expects the external costs for locate delivery services to materially increase from the amounts included in the 2024 Test Year Forecast as a result of the mandate of absolute liability compliance for five-day and ten-day locate deliveries depending on the scope of the excavation project. To manage the incremental costs, Enbridge Gas is proposing a new locate delivery service charge for third-party contractors and other utilities that require a field locate, as provided at Exhibit 8, Tab 3, Schedule 1. Enbridge Gas is also proposing a new variance account to record the difference between actual and 2024 Test Year Forecast external locate delivery service costs, offset by the revenue collected through the new locate delivery service charge. A description of the proposed variance account is provided at Exhibit 9, Tab 1, Schedule 3.

5. Energy Services (ES)

5.1. Mandate and Operational Structure

86. The Energy Services (ES) department is organized into five main groups: Gas Supply, Gas Control & Management, Storage & Transportation Business Development, Storage & Transportation Sales and Utility Portfolio Management.

87. The Gas Supply group is responsible for the creation of the Company's Gas Supply Plan. Its mandate includes the planning and procurement of storage, transportation, and gas commodity to meet the annual, seasonal, and peak day requirements of Enbridge Gas's in-franchise customers. The Gas Supply Plan aligns with the OEB's gas supply planning guiding principles to ensure it achieves the goals of cost-effectiveness, reliability and security of supply, and alignment with public policy. This group also focuses on the management of upstream regulatory issues by representing the interests of Enbridge Gas's customers with the Canada Energy Regulator (CER), Federal Energy Regulatory Commission (FERC), and various industry working groups that impact its upstream gas supply portfolio.

88. The Gas Control & Management group is responsible for daily demand forecasting and operational management of the gas transportation, storage and distribution systems, including nominations on upstream pipelines. In addition, this group also manages scheduling and confirming nominations on its transportation and storage assets, compressor fuel management, measurement integrity and verification, gas supply contract administration and reporting, and storage and transportation contract administration. Gas Control also has responsibility for monitoring all Enbridge Gas's transmission, storage, and distribution operating systems to ensure its safe and reliable operation on a real time basis.

89. The Storage & Transportation Business Development group is responsible for overseeing the commercial development of Enbridge Gas storage and transportation assets. This includes evaluating and planning the capacity of underground gas storage and transportation pipelines to ensure that there is sufficient capacity to meet the demands of the storage and transportation system.

90. The Storage & Transportation Sales group is accountable for generating and maximizing revenues and asset value by selling both long-term and short-term storage and transportation products to customers that include local distribution companies (LDCs), marketers, power generators and U.S. Northeast customers. This group also provides transactional services to create value from storage and transportation assets when they are not being used to meet the needs of utility customers, with the revenues generated being shared between customers and the shareholder.

91. The Utility Portfolio Management (UPM) group is responsible for facilitating the Company's portfolio of initiatives for prioritization, alignment, resourcing, and reporting. This includes assessing the portfolio of initiatives to ensure they deliver value to stakeholders including customers, shareholders, and employees. Initiatives in the portfolio include integration and efficiency projects as well as projects to enable future growth. This group creates alignment to ensure initiatives are reviewed and approved through supporting governance frameworks such as the asset planning and financial planning processes.

5.2. *ES Costs – Variance Analysis*

92. Table 6 provides a summary of O&M costs from 2018 with combined EGD and Union actuals through to the 2024 Test Year using the current amalgamated

structure to facilitate year-to-year comparability. The cost categories in the Particulars column reflect the primary contributors of ES's historical actuals, forecasts and associated variance drivers. The other O&M category is comprised of smaller cost items such storage pool usage fees and travel and accommodations. All costs are shown for regulated operations before capitalization is applied.

Table 6
Energy Services O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual (1)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Salaries & Wages	EGI	17.7	14.8	11.9	12.5	14.0	14.9	15.9
2	Contract Services	EGI	2.0	1.5	1.4	1.7	1.1	1.3	1.3
4	Other O&M	EGI	1.2	1.1	1.0	1.4	2.3	2.5	0.7
5	Total	EGI	20.9	17.4	14.3	15.6	17.4	18.7	17.9

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

93. Overall, the costs for ES decline from $20.9 million in 2018 to $17.9 million in the 2024 Test Year, an annual average decrease of 2.6%. Significant O&M reductions were due to synergies resulting from restructuring which were partially offset later by impacts due to inflation and enhancements to storage integrity and cyber security management programs and energy transition support.

ES – 2019 Actual vs 2018 Actual

94. After amalgamation in 2019, ES costs decreased by $3.5 million compared to the prior year. This was primarily a result of $2.9 million in salaries & wages savings from the 2019 restructuring and lower severance as 2019 severance was captured

in integration-related costs (please see Section 9 and Exhibit 1, Tab 9, Schedule 1). A large portion of the restructuring savings were due to the centralization of the Gas Control, Operational Planning, Nominations functions and Gas Supply. Previously, these teams were spread between Edmonton (EGD) and Ontario (EGD/Union) but are now centralized in Ontario. A major component of this initiative included the centralization of the Supervisory Control and Data Acquisition (SCADA) system, which is provided in more detail at Exhibit 1, Tab 9, Schedule 1, Section 2.2.

ES – 2020 Actual vs 2019 Actual

95. In 2020, ES costs decreased by $3.1 million largely from lower salaries & wages of $2.9 million from the combination of VWO along with the full year effectiveness of the previous year's FTE reductions.

ES – 2021 Actual vs 2020 Actual

96. In 2021, ES costs increased by $1.3 million as compared to 2020. Merit increases for salaries & wages and inflationary increases in contract services were the primary drivers.

ES – 2022 Estimate vs 2021 Actual

97. The 2022 Estimate is expected to be $1.8 million higher than 2021. The increase is primarily driven by higher salaries & wages of $1.5 million from a need for additional FTE resources. These additional resources are required to support integrity management of storage wells and reservoir assets and to better align the permitting process on Enbridge Gas's distribution system and gas control outage coordination responsibilities. The $0.9 million increase in other O&M is driven by inflation pressures and increased travel costs previously lower than normal due to COVID-19 restrictions. Offsetting these increases is $0.6 million lower contract services

resulting from a realignment of integrity inspection responsibilities between ES and Engineering.

ES – 2023 Bridge Year vs 2022 Estimate

98. The 2023 Bridge Year is expected to be higher than the 2022 Estimate by $1.3 million primarily due to higher salaries & wages from merit increase and additional resources to oversee storage and transportation enhancement initiatives, enhance cyber security in relation to gas control centers, and to support energy transition.

ES – 2024 Test Year vs 2023 Bridge Year

99. The 2024 Test Year costs for ES are forecast to be lower than 2023 Bridge Year estimate by $0.8 million. The primary driver of the year-over-year reduction is other O&M caused by the elimination of $1.9 million of Dow Moore and Black Creek storage pool charges. Currently, the EGD rate zone charges[11] the Union rate zones under Rate 325 for the use of the Dow Moore and Black Creek storage pools. Enbridge Gas is proposing to remove Rate 325 and implement a non-utility cross charge thereby eliminating this item from O&M. Please see Exhibit 8, Tab 2, Schedule 5, Section 5 for more details. This is partially offset by higher salaries & wages due to $0.7 million in merit increases and $0.3 million for resources to support ongoing portfolio management activities including leadership alignment and prioritization, resource utilization and coordination for priority initiatives on behalf of the Company.

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[11] The original agreements for the Black Creek and Dow Moore storage pools were terminated upon amalgamation. Enbridge Gas continued with the Rate 325 monthly invoices between the EGD and Union rate zones during the deferred rebasing term as proposed in the MAADs proceeding at EB-2017-0306/EB-2017-0307, Exhibit C.SEC.1, Attachment 1, p.1.

6. Engineering and Storage & Transmission Operations (Engineering & STO)

6.1. Mandate and Operational Structure

100. The Engineering & STO department is accountable for managing Enbridge Gas's transmission, distribution, and storage assets. The department is accountable for evaluating the effectiveness of Enbridge Gas programs, and ensuring ongoing integrity, reliability, and industry competitiveness. The department is organized into five groups: Integrity and Asset Management, Engineering, Engineering Services & Integrated Management System (IMS), System Improvement, and Storage & Transmission Operations (STO).

101. Integrity and Asset Management is responsible for managing the integrity of transmission, distribution and storage assets as well as maintaining overall governance of Enbridge Gas's assets over their lifecycle. A goal of this group is to reduce asset uncertainty by implementing standards and learning from best-practices and past experiences to implement new approaches that proactively eliminate incidents. Within this group, Integrity Management monitors the condition of Enbridge Gas's pipeline system to avoid and eliminate failures through mitigation activities. Transmission Integrity implements and administers Pipeline Integrity Management Programs to meet legislative requirements for high stress natural gas pipelines which reduces the risk of these lines. Distribution Integrity analyzes data to determine risk-based recommendations, expected life, and replacement strategies for distribution assets. Facilities Integrity and Storage Integrity departments ensure that pipeline facilities and the storage system are suitable for continued, safe, reliable service and comply with applicable regulations. Asset Management is responsible for the governance, development, implementation, and effectiveness of Enbridge Gas's procedures to manage the lifecycle of its assets, balancing cost, risk and performance.

102. Engineering has the primary responsibility for developing and maintaining policies, procedures and standards to support the design, construction, maintenance, and decommissioning of the Enbridge Gas distribution system. The technical policies, procedures and standards are developed to ensure compliance with all applicable codes, regulations and standards, as well as the safety, quality and environmental stewardship goals of Enbridge Gas. Within this group, Materials & Utilization Engineering is accountable for gas quality, interpretation of the Canadian Standards Association (CSA) B149 code for gas burning appliances, and developing internal standards for polyethylene fusions, corrosion and welding to ensure compliance. Systems Measurement is accountable for all meter shop operations, including the measurement accreditation program. Distribution Optimization Engineering is accountable for the optimal design and analysis of long-range planning to determine specific needs for projects, providing technical support to the field. Pipeline Engineering is accountable for all design related to pipeline assets, RNG, CNG, and hydrogen. Stations & Utilization Engineering is accountable for all design related to station assets, along with maintaining policy, procedure and design specifications related to stations, electrical, controls and utilization.

103. Engineering Services and IMS provide a variety of functions that support the activities of Enbridge Gas. The Content Management Program is responsible for the integration, implementation and publication of Enbridge Gas content as well as documentation governance. Quality Management is accountable for quality assurance (QA) activities including field, process and program audits, the operator qualification program and QA reporting. In addition, this team oversees the Material Evaluation Centre which provides key services such as new material testing and testing of failed components to identify corrective actions. Technical Training

develops and delivers training for both field and office staff so that all workers are competent and qualified for the tasks they perform. The IMS provides governance and oversight to fulfill Enbridge Gas's commitment to manage risk and assure safety, reliability and compliance for our assets, our employees, the public and the environment. Emergency Management plans and executes emergency and incident investigation programs which include completing emergency exercises, providing emergency preparedness and response training, and completing investigations and producing investigation reporting.

104. System Improvement (SI) executes projects including Transmission and Facilities Integrity Programs, community expansion and transit program execution (provincial programs), and projects supporting new and emerging technologies (RNG, CNG, hydrogen, etc.). SI has accountability to oversee and manage the design, approval, construction and commissioning of large-scale gas distribution infrastructure projects, including pipelines, gate stations and integrity retrofit work. This group also provides services for Enbridge Gas such as lands, environmental, permitting, and telemetry.

105. Storage & Transmission Operations (STO) is accountable for the strategy, development and operation of Enbridge Gas's gas storage, compression and transmission business. This group is accountable for operating and maintaining the Company's storage facilities of 316 PJ of underground gas storage, 800,000 compression horsepower and over 5,000 km of transmission pipeline. The storage of natural gas is critical to the economic operation and system security of the Company's gas distribution business.

6.2. Engineering & STO Costs – Variance Analysis

106. Table 7 provides a summary of O&M costs from 2018 with combined EGD and Union actuals through to the 2024 Test Year using the current amalgamated structure to facilitate year-to-year comparability. The cost categories in the particulars column reflect the primary contributors of Engineering & STO's historical actuals, forecasts and associated variance drivers. The other O&M category is comprised of transfers out of regulated costs to unregulated storage operations, offset with training and travel and accommodations. All costs are shown before capitalization is applied.

Table 7
Engineering & STO O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual (1)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Salaries & Wages	EGI	74.3	69.8	63.8	64.6	70.4	74.9	79.4	
2	Contract Services	EGI	40.6	36.5	29.4	35.8	57.6	63.3	61.5	
3	Materials & Supplies	EGI	9.4	10.2	8.5	10.8	10.4	10.9	11.1	
4	Rents & Leases	EGI	8.7	8.8	9.1	10.3	12.0	12.3	12.5	
5	Other O&M	EGI	(20.0)	(15.7)	(15.2)	(10.4)	(4.8)	(3.4)	(9.6)	/u
6	Total	EGI	113.0	109.6	95.6	111.1	145.6	158.0	154.9	/u

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

107. Engineering & STO's costs vary from year-to-year based on the timing of proactive measures taken to maintain the integrity, safety and reliability of Enbridge Gas's assets. One of the key drivers of this group's historical cost variability is the Integrity Management Program (IMP). Enbridge Gas has developed a risk model to assess

the primary risks for pipeline assets in the distribution system in order to prioritize those approaching end-of-life which need to be replaced. These primary risks include key threats such as external corrosion and third-party damage. The risk model is built on the Company's geographic information system (GIS) with additional data layered in regarding asset condition, probability of failure and calculated consequence. While the IMP continues to evolve based on industry best practices and incident learnings, it is used to identify and target integrity work over-time across distribution, transmission, facilities, and storage downhole assets. The transmission pipeline assets risk model has been enhanced with additional threats and consequences, as well as the development of safety targets to further assess the risk of Transmission Integrity Management Program (TIMP) assets.

108. The Integrity team carries out proactive inspections every year and determines re-inspection frequencies based upon inspection results. The resulting work varies each year, and even intra-year, as re-inspection intervals are based upon risk, not a set timeline. These inspections can also lead to mitigation efforts that are customized to the unique requirements of the assets, therefore creating additional variability. Mitigation scope and timing is based on risk assessment and required mitigation timelines and affects spend variability. Additionally, there is interdependency with the Operations department where remediation issues may be identified through fieldwork and not due to Integrity's proactive inspections. Finally, external factors such as industry incidents, new integrity standards, industry best-practices, etc., may change planned work. Overall, the determination of integrity work is informed by dynamic factors leading to risk-based decisions which drive the annual costs.

109. Overall, the costs for Engineering & STO increase from $113 million in 2018 to $154.9 million in the 2024 Test Year, an annual average increase of 5.4%. /u
Significant O&M reductions were due to synergies and efficiencies resulting from restructuring and lower spend due to COVID-19 restrictions. These cost reductions were later offset by increased costs to address work back logs, integrity program enhancements, risk modelling and enhancements to standards as well as rising inflation.

Engineering & STO – 2019 Actual vs 2018 Actual

110. Engineering & STO's 2019 costs were lower than 2018 by $3.4 million. Salaries & wages decreased by $4.5 million due to integration savings from the 2019 restructuring and lower severance as 2019 severance was captured in integration-related costs (please see Exhibit 1, Tab 9, Schedule 1, Section 2.3). The $4.1 million reduction in contract services was due to lower storage operation repairs and maintenance costs because of a major power turbine repair in 2018. These reductions were offset by increased other O&M costs of $4.3 million primarily due to an STO self insurance claim where Union was reimbursed by Spectra in 2018 for a major engine repair that occurred in 2017.

Engineering & STO – 2020 Actual vs 2019 Actual

111. In 2020, Engineering & STO costs decreased by $14 million with $6 million in lower salaries & wages costs resulting from the VWO program and the full year effectiveness of the 2019 restructuring. Contract services decreased by $7.1 million largely as a result of the impact COVID-19 had on the Company's operations, leading to a reduced scope of IMP work predominantly due to scheduling impacts. A reduction in hydro costs led to the $1.7 million decrease in materials & supplies due to STO's use of generators to power the stations on peak hydro usage days.

Engineering & STO – 2021 Actual vs 2020 Actual

112. In 2021, costs increased by $15.5 million compared to the prior year. Contract services increased by $6.4 million primarily due to the gradual return to normal operating conditions as COVID-19 restrictions eased and audit findings and risk modelling enhancements led to higher planned IMP inspections. Additionally, $1 million of telematics costs were transferred from Operations. Materials & supplies increased by $2.3 million due to a write-off of materials related to meter shop inventory obsolesce and cancellation of capital projects. Rents & leases increased by $1.2 million from an increase in easement costs resulting from higher land valuations. Property values adjacent to easements are used as a basis for reassessment at time of renewal. Finally, other O&M increased by $4.8 million due to a lower allocation of costs to unregulated storage along with increased employee training as COVID-19 restrictions were lifted.

Engineering & STO – 2022 Estimate vs 2021 Actual

113. The 2022 Estimate is expected to be $34.5 million higher than the 2021 actual. The primary driver of the increase is higher contract services of $21.8 million to address the backlog of work created by COVID-19's impact as well as higher planned IMP inspections as a result of risk modelling enhancements. In addition, a $5.8 million increase in salaries & wages is made up of merit and FTE increases to support compliance work relating to enhancements in Integrity Operations as a result of the Enbridge Integrity Management Framework Standard (IMFS)[12], increased environmental program support, and STO Plant Operations maintenance requirements. Rents & leases costs are expected to increase by $1.7 million from

[12] IMFS seeks to reduce or eliminate risks in the Enbridge Gas pipeline network. The program delivers benefits by minimizing potential incidents, service disruptions, and unexpected expenses, all of which have environmental and societal impacts.

higher land valuations as renewal reassessments continue. Lastly, the $5.6 million increase in other O&M is due to an increase in travel and employee training following the lifting of COVID-19 restrictions.

Engineering & STO – 2023 Bridge Year vs 2022 Estimate

114. The 2023 Bridge Year is higher than the 2022 Estimate by $12.4 million. Contract /u services increases by $5.7 million as a result of $6.4 million for IMP based on risk modelling and $5.7 million for environmental programs[13], engineering and integrity work including consulting costs for excess soil legislation, environmental compliance approval certification, records reliability work to support FIMP, integrity software support and consulting for the hydrogen blending project. Salaries & wages are expected to increase by $8.5 million due to merit as well as FTE increases to support compliance with IMFS, to execute quality management and training sustainment due to expansion of the distribution system, and to implement new TSA guidelines to manage cyber security activity within storage operations. The increases in contract services and salaries & wages were partially offset by embedded productivity savings, which are preliminary estimates as the Company has not conclusively identified the additional productivity opportunities that will deliver these savings commitments. The other O&M increase of $1.4 million is due /u to increased travel & accommodations and employee training.

[13] The variability on annual spend on environmental programs is dependent on the number of legacy sites that are no longer operated by the Company and the requirement to address historical contamination from operations.

Engineering & STO – 2024 Test Year vs 2023 Bridge Year

115. The 2024 Test Year costs are expected to be $3.1 million lower than the 2023 Bridge Year. The $4.5 million increase in salaries & wages is driven by merit and FTE increases to support the maximum operating pressure (MOP) verification program[14]. The program's scope will be expanded to include Union pipelines with the goal of demonstrating and understanding pipeline operating stresses in order to inform the Integrity program and facilitate the assessment of the Company's overall risk profile for higher stress pipeline assets. The contract services decrease of $1.8 million is a result of embedded productivity offsetting an increase of $1 million in contractor resources to support MOP. Embedded productivity savings are preliminary estimates as the Company has not conclusively identified the additional productivity opportunities that will deliver these savings commitments. Other O&M decreased by $6.2 million due to impacts from the harmonization of the unregulated allocation methodology provided at Exhibit 1, Tab 13, Schedule 2. /u

7. Central Functions (CF)

116. Both EGD and Union historically received corporate cost allocations from their respective corporate parents. In 2018, following the merger of Enbridge and Spectra, Enbridge established CFs[15] that provide typical shared services to its affiliate companies and implemented an internally developed Central Functions Cost Allocation Methodology (CFCAM) to allocate the CF costs amongst the service recipients. Please see Exhibit 4, Tab 4, Schedule 3, Section 2 for a

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[14] The MOP verification program supports an industry best practice that ensures pipeline operating limits are verified through assessments. This best practice was developed as a result of severe industry incidents and has been implemented to ensure asset records are traceable, verifiable, complete and that operating limits of pipelines are understood by the operators.

[15] CF are business functions that provide shared strategic management and policy support relating to the areas of Finance, Human Resources, Technology & Information Systems, Insurance, Legal, Public Affairs & Communications, Safety & Reliability and Supply Chain Management.

comprehensive overview of the CFCAM including CF service descriptions, cost allocation methods, and cost drivers. The CFCAM was reviewed by Guidehouse Canada Ltd. (Guidehouse), an external consultant, whose findings are provided at Exhibit 4, Tab 4, Schedule 3, Attachment 3.

117. Table 8 provides total CF costs from 2018 to the 2024 Test Year. From 2018 to 2021 CF costs were relatively consistent considering the impact of inflation and reductions driven from efficiencies and synergies as a result of restructuring and systems consolidation due to integration. Beyond 2021 there are a few key factors impacting CF costs. First, TIS costs increase as a result of technology industry shifts to an 'as a service' model driving costs from capital to O&M. Technology modernization has resulted in a shift from capital intensive traditional on-site physical data centres to O&M intensive infrastructure and software 'as a service' models, leading to higher O&M related to the implementation and sustainment of solutions in an 'as a service' model. Additional investments have also been made in cyber security on information and operational technologies. Second, improvements to CFCAM in 2021 have led to a more representative breakdown of benefit[16] costs between Business Unit (BU)[17] and CF, resulting in an increase in the benefit costs associated with CF (please see Section 8 for further explanation). Finally, depreciation allocations will increase in 2024 from depreciation expense expected from the implementation of Oracle Cloud at Enbridge Gas. Please see Exhibit 4, Tab 4, Schedule 3, Section 2.5 for a further breakdown of the CF costs shown in Table 8 along with variance analysis.

[16] Pension and OPEB, incentive pay and health and other employee benefits.
[17] Benefits for Enbridge Gas employees not part of CF.

Table 8
Central Functions O&M

Line No.	Particulars ($ millions)	Utility	2018 Actual (1)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Central Functions	EGI	230.5	237.3	244.6	279.8	336.7	352.9	377.1	/u

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

8. Business Unit (BU) Benefits

118. BU benefits are centrally managed costs which include pension and OPEB, short-term (STIP) and long-term (LTIP) incentive pay and health and other employee benefits for Enbridge Gas employees not part of CF. Identifying BU and CF benefits separately better aligns these costs to the services supported by the employees assigned. The process of tracking and reporting BU and CF benefits changed in 2021. As a result of CFCAM improvements, all benefit costs for CF Enbridge employees providing services to Enbridge Gas and certain employee payroll related benefit costs were specifically identifiable leading to a more representative breakdown between BU and CF benefits. Please see Exhibit 4, Tab 4, Schedule 3, Section 2 for more information on CF benefit costs.

119. For the development of the 2022 to 2024 pension and OPEB forecast, Enbridge Gas engaged Mercer Canada Limited (Mercer). Attachment 1 contains Mercer's May 2022 report (pages 1 to 89) and Mercer's January 2023 updated forecast /u (pages 90 to 102) to the May 2022 report, which provides actuarial estimates of pension and OPEB plan accrual costs in accordance with US GAAP and cash funding requirements. For non-pension and OPEB benefit costs, inflation

adjustments and impacts from changes in FTEs were layered onto the 2022 Estimate. Inflation was projected at 2.4% for 2023 and 2.2% for 2024, as presented at Exhibit 3, Tab 2, Schedule 4. Table 9 shows the BU benefit costs from 2018 to the 2024 Test Year.

Table 9
Business Unit Benefits

Line No.	Particulars ($ millions)	Utility	2018 Actual (1)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	BU Benefits	EGI	144.1	158.4	148.4	143.3	103.7	111.8	111.1	/u

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

120. From 2018 to 2021, BU benefit costs ranged from $143.3 million to $158.4 million. The year-over-year fluctuation is primarily attributable to changes in pension and OPEB resulting from actuarial valuations and changes in benefit expense for STIP and LTIP impacted by Enbridge Gas's performance metrics, partially offset by the reduction in FTEs. Health and other employee benefit expenses have also fluctuated due to insurance and medical industry trends and workforce levels which has trended lower post-amalgamation from restructuring in 2019 and VWO in 2020. While salary and wage reductions are included in the operating department costs, associated benefit impacts are reflected in the historical amounts within this section. Contributing to the decline in 2021 is the change in identification of BU and CF benefits from improvements in CFCAM (please see paragraph 116). The BU benefits amount represents a lower portion of the overall benefits amount than estimated in prior years.

121. In 2022 Estimate, BU benefit costs are forecast to decline by $39.6 million as compared to 2021. Pension and OPEB are the primary driver of the year-over-year decline due to a $26 million reduction from Mercer's actuarial valuation. The remaining difference is attributable to a $14.8 million lower STIP forecast resulting from Enbridge Gas's performance in 2021, partially offset by a small increase in health and other benefits due to expected FTE growth and inflation assumptions. In 2023 Bridge Year, BU benefit costs are expected to increase by $8.1 million as compared to 2022. This increase is due to higher pension and OPEB expense of /u $9.6 million based on Mercer's actuarial valuation, along with $4.8 million of increased STIP and $3.3 million of increased health and other benefit costs mainly attributable to the expected year-over-year FTE growth and inflation assumptions. Partially offsetting these increases is $9.8 million lower amortization of Union's pre-amalgamation actuarial losses[18]. In 2024 Test Year, BU benefit costs are expected to decline by $0.7 million as compared to 2023. This decrease is primarily due to a $2.2 million reduction resulting from ceasing amortization of Union's pre-amalgamation actuarial losses. Recovery of the unamortized amount has been proposed through clearance of the APCDA (please see Exhibit 9, Tab 2, Schedule1 for more information). A $1 million decrease in pension and OPEB expense based /u on Mercer's actuarial valuation and a $2.5 million inflationary increase in STIP, LTIP and benefit costs account for the remaining portion of the year over year change.

[18] As outlined in the 2019 Utility Earnings and Disposition of Deferral & Variance Account Balances Application (EB-2020-0134) Exhibit C, Tab 1, pp.9-12. Enbridge Gas has recorded a regulatory asset within the Accounting Policy Change Deferral Account (APCDA) representing Union's pre-amalgamation unamortized actuarial losses. /u

9. Integration-Related Costs

122. Integration-related costs incurred to pursue alignment and harmonization initiatives have been separately tracked in O&M beginning in 2019. Also included are severance costs associated with any FTE reductions brought about by restructuring. These costs were a requirement for Enbridge Gas to pursue integration and achieve synergies while maintaining safety and reliability commitments.

123. Table 10 shows total O&M integration costs along with integration severance for the 2019 restructuring and 2020 VWO. Integration costs largely represent dedicated FTEs and consultants working on aligning processes and procedures, harmonizing methodologies, and implementing common tools and systems. A number of these initiatives have contributed to synergy savings through the deferred rebasing term and in to the 2024 Test Year. By the end of 2023, significant progress on integration will be realized with benefits being passed on to customers and integration related costs will be eliminated. More detail on integration costs and synergy savings is provided at Exhibit 1, Tab 9, Schedule 1.

Table 10
Integration-Related Costs

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	Total
			(a)	(b)	(c)	(d)	(e)	(f)
1	Integration Costs	EGI	10.2	46.4	49.8	35.2	19.5	161.1
2	Integration Severance	EGI	41.5	77.7				119.1
3	Total Integration-Related Costs	EGI	51.7	124.0	49.8	35.2	19.5	280.3

10. Capitalized Overhead Costs

124. Overhead costs are incurred to support the overall delivery of utility services, including capital infrastructure development. They are distinct from direct costs which can be linked directly to specific projects. Instead, overheads cover a variety of support functions and are allocated to capital based on cost drivers reflecting causation. Capitalization of overhead costs serves to recognize the portion of O&M expenses that support activities required to carry out capital projects.

125. Enbridge Gas undertook to harmonize its capitalization methodology in 2019 and the proposed harmonized methodology was implemented in 2020. Please see Exhibit 2, Tab 4, Schedule 2 which details the methodology submitted for approval in this Application. Impacts of the change in methodology have been recorded in APCDA (please see Exhibit 9, Tab 2, Schedule 1) for the deferred rebasing term.

126. Prior to amalgamation, EGD and Union had separate overhead capitalization methodologies which were approved by the OEB. While the approaches were different, the principles of cost categorization, the use of drivers and the reliance on causal linkage to capital activity were similar.

127. Table 11 presents capitalized overhead amounts for Enbridge Gas. From 2018 to 2019, the overhead amounts combine the overhead capitalization amounts from EGD and Union although methods and rates were different. Harmonized rates are in effect from 2020 to 2024.

Table 11
Overhead Capitalization

Line No.	Particulars ($ millions)	Utility	2018 Actual (1)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Overhead Capitalization	EGI	(226.5)	(237.2)	(224.3)	(234.2)	(268.9)	(301.1)	(310.4)

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

128. In 2019, overhead capitalization increased by $10.7 million. This increase is attributable to the increase in gross O&M from 2018 to 2019 and the static nature of year-to-year historical capitalization rates, most notably for EGD.

129. Overhead capitalization decreased by $12.9 million in 2020, as compared to 2019, to $224.3 million. The year-over-year decrease is attributable to lower gross O&M for operating departments such as Operations and Engineering & STO that have a relatively high involvement in capital activity, and therefore higher capitalization rates as compared to other operating departments. The impact of lower gross O&M is partially offset by the implementation of the harmonized overhead capitalization methodology in 2020 which capitalizes a higher amount of O&M based on allocators more closely aligned with drivers of capital activity.

130. In 2021, overhead capitalization increased by $9.9 million to $234.2 million. The increase was driven by higher capital expenditures influencing overhead capitalization rates as per the harmonized methodology and higher gross O&M, most notably for Operations, Engineering & STO, and CF.

131. In 2022, overhead capitalization increased by $34.7 million to $268.9 million. The increase is primarily attributable to the expected increase in gross O&M for the 2022 Estimate for Operations, Engineering & STO, and CF. As outlined in the preceding sections of this Exhibit, the increase in gross O&M is driven by Operations and Engineering & STO, both of which contribute most to the Company's capital programs, along with CF.

132. Overhead capitalization is expected to increase by $32.2 million and $9.3 million for the 2023 Bridge Year and 2024 Test Year, respectively. These increases are driven by 1) a higher proportion of capital activity leading to an increase in capitalization rates and labour burden and 2) the increase in gross O&M projections.

133. The increase in capital activity beginning in 2021 (please see Exhibit 2, Tab 5, Schedule 3, Table 6) results in higher capitalization rates for Operations due to the group's substantial involvement in Enbridge Gas's capital programs. The capitalization rate for CF, who acts in support of Enbridge Gas's overall activities, also increased as the harmonized methodology better associates the level of capital activity with CF through a weighted average rate that incorporates all departmental rates (such as Operations). Finally, as capitalized labour increases with involvement in the Company's capital programs, a corresponding increase in labour burdening will also occur.

134. The increase in gross O&M costs has also contributed to an increase in overhead capitalization (as provided in Table 1 by removing overhead capitalization in line 8 from utility O&M in line 12). As previously outlined for 2022, the impact of gross O&M on the increase in overhead capitalization is driven by Operations and

Engineering & STO, both of which contribute most to the Company's capital programs, along with CF.

11. Utility O&M

135. This section provides a summary of utility O&M and cost driver tables. Table 12 summarizes the 2022 Estimate, 2023 Bridge Year, and 2024 Test Year amounts for utility O&M.

Table 12
Utility O&M

Line No.	Particulars ($ millions)	Utility	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	
1	Business Development & Regulatory	EGI	35	40	47	
2	Customer Care	EGI	118	124	135	
3	Distribution Operations	EGI	309	331	338	
4	Energy Services	EGI	17	19	18	
5	Engineering & STO	EGI	146	158	155	/u
6	Central Functions	EGI	337	353	377	/u
7	BU Benefits	EGI	104	112	111	/u
9	Overhead Capitalization	EGI	(269)	(301)	(310)	
10	Utility O&M excl. Integration and DSM	EGI	797	835	871	/u
11	Integration-Related Costs	EGI	35	20	0	
12	DSM	EGI	132	167	175	/u
13	Utility O&M	EGI	964	1,022	1,046	/u

136. As noted in the preceding sections of this evidence, operating departments are projecting cost increases starting in the 2022 Estimate and persisting into the 2024 Test Year. Return to pre-COVID-19 workload while continuing to address the backlog of deferred work caused by COVID-19 restrictions will require increased

staffing and contractor resources. Cost increases are also expected for integrity management, cross bore inspections and locates due to Bill 93 to meet compliance obligations and ensure safety and reliability as the distribution system continues to grow. CF cost increases are driven by higher TIS costs due to the adoption of ‘as a service’ technology, cyber security measures and support costs for Enbridge Gas technology projects. Inflationary pressures are expected to increase costs for all departments, most notably in the areas of fuel and fleet repair, consulting, postage, pulp and paper costs, and bad debt. Resourcing challenges, both in labour and materials, are also expected to drive costs higher. Offsetting the impact of these increases are lower benefit costs due to decreasing pension costs, as projected by actuarial valuations.

137. Cost increases in the 2023 Bridge Year are related to inflationary pressures, increased locate volumes and associated costs from impacts of Bill 93, continued cross bore inspections and integrity program work. Hearing and intervenor costs are also expected to drive an increase in contract services as the rebasing proceeding gets underway. Increases in bad debt, contact center support and third-party contract costs are driven by and required as part of ongoing customer growth. TIS costs will also continue as a key driver of costs in 2023 with the migration to an ‘as a service’ model. BU benefits costs are also higher due to higher pension and /u
OPEB expense based on actuarial valuations, along with increased STIP and health and other benefit costs mainly attributable to FTE growth and inflation assumptions. Offsetting these increases is higher overhead capitalization due to a higher level of capital activity and higher gross O&M.

138. The build-up to 2024 Test Year O&M includes inflationary pressures, bad debt and costs that were previously captured within deferral and variance accounts to

present full cost-of-service. CF cost increases continue to be driven by TIS, as previously discussed, along with higher depreciation expected from the implementation of Oracle Cloud at Enbridge Gas.

139. Offsetting 2024 cost pressures are integration synergies and productivity savings of $86 million and $35.2 million, respectively. Although no additional synergies or opportunities for additional productivity have been identified, Enbridge Gas has embedded gross O&M productivity savings of $20.7 million ($13.9 million net O&M) and $28.5 million ($18.1 million net O&M) for the 2023 Bridge Year and 2024 Test Year, respectively, to further mitigate cost pressures. Although specific measures to achieve embedded productivity are unidentified, Enbridge Gas is committed to continued cost management to pass on these additional savings to customers for the 2024 Test Year. Together, integration synergies and productivity initiatives, including incremental net O&M embedded productivity, represent $121.2 million of annual savings for customers in the 2024 Test Year.

140. Enbridge Gas has worked intensively to achieve and preserve integration synergies made possible by amalgamation. Without these synergies, cost pressures would have had a more significant impact on operating expenses, and 2024 Test Year costs would have been significantly higher. While cost increases are expected to offset synergy savings achieved in the 2024 Test Year, costs are justified, reasonable, and fair as compared to prevailing inflation rates and Enbridge Gas's peers. Please see the overview of O&M costs, provided at Exhibit 4, Tab 4, Schedule 1. Enbridge Gas continues to deliver safe and reliable service at reasonable rates to its customers.

141. Attachment 2 provides a summary of cost drivers and savings, discussed throughout this Exhibit, for 2019 actuals to the 2024 Test Year.

Mercer

EGI Pension and Benefit Plans

Estimated 2022-2024 Net Periodic Benefit Costs

May 2022

welcome to brighter

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan’s estimated financial condition at a particular point in time; it does not predict a pension plan’s future financial condition or its ability to pay benefits in the future.

If maintained indefinitely, a plan’s total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date.

The content of the report may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer’s permission. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used, or relied upon without reference to the report as a whole.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plans’ actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future, and other factors.

We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes, and the results are sensitive to all the assumptions used in the valuation.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security, and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic, and societal factors, including financial scenarios that assume future sustained investment losses.

Funding calculations reflect our understanding of the requirements of pension legislation applicable to the pension plans, the *Income Tax Act*, and related regulations that are effective as of the valuation date. The accounting calculations have been made in accordance with our understanding of applicable laws and regulations. Mercer is providing the valuation report in its capacity as actuary and as such, the report is not a substitute for advice from an accountant or lawyer. Mercer is not an accountant or auditor and is not responsible for the interpretation of, or compliance with, accounting standards; citations to, and descriptions of accounting standards provided in this report are for reference purposes only. Mercer is also not a law firm, and the analysis presented in this report is not intended to be a legal opinion. A user of this report should consider securing the advice of legal counsel with respect to any legal matters related to this report.

Contents

1

Introduction

To Enbridge Gas Inc.

At the request of Enbridge Gas Inc. (the "Company"), we have prepared estimates of the Company's share of net periodic benefit costs ("accrual costs") and (minimum) cash requirements for fiscal years 2022 to 2024 for the following pension plans:

- Retirement Plan for Employees of Enbridge Inc. and Affiliates (the "EI RPP");
- Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "EGD RPP");
- The Enbridge Supplemental Pension Plan (the "EI SPP");
- Pension Choices Plan for Employees of Westcoast Energy Inc. and Affiliated Companies (the "Pension Choices Plan");
- Union Gas Management and Supervisory Pension Plan (the "M&S Plan");
- Union Gas Bargaining Unit Pension Plan (the "BU Plan");
- Union Gas Pension Plan for Salaried Employees Formerly Employed by Centra Gas Inc. (the "Salaried Plan");
- Union Gas Pension Plan – Group One (the "G1 Plan");
- Union Gas Pension Plan – Group Three (the "G3 Plan");
- Spectra Energy Supplemental Executive Retirement Plan and Spectra Energy Maximum Pension Limits Plan (collectively the "LSE SERP");
- Supplemental Executive Retirement Plan of Enbridge Gas Distribution and Affiliates (the "EGD SERP");
- Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. (the "EGD SSERP");

And the following benefit plans:

- Enbridge Gas Distribution Inc.'s Non-Pension Post Retirement Benefits Plan (the "EGD OPEB Plan");
- Spectra Energy Corp's Non-Pension Post Retirement Benefits Plan (the "Spectra OPEB Plan");

based on economic conditions at April 30, 2022. The actual accrual costs and the minimum cash funding requirements in respect of fiscal years 2022 to 2024 may differ (and could differ significantly) from the amounts estimated in this report, and will be based on future market conditions and the respective plans' economic and demographic experiences.

The pension plans have been grouped as follows:

- "Legacy Enbridge Plans" includes the EI RPP, EGD RPP, EI SPP, EGD SERP and EGD SSERP;
- "Legacy Spectra Closed Plans" includes the M&S Plan, Salaried Plan, BU Plan, G1 Plan and G3 Plan;
- "Legacy Spectra Plans" includes the Legacy Spectra Closed Plans, Pension Choices Plan, and LSE SERP;

The "pension plans" refers collectively to all plans listed above.

The Company participates in pension and benefit plans administered by Enbridge Inc. The accounting accrual costs and funding requirements of these plans are allocated to participating Enbridge businesses in accordance with Enbridge Inc.'s funding policy and internal accounting policies. We have determined the Company's share of these plans in accordance with our understanding of these policies.

The only purposes of this report are to present actuarial estimates of pension and benefit accrual costs in accordance with US GAAP and the cash funding requirements for 2022 to 2024 for the plans in which the Company participates. We understand this report may be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery of pension and benefit costs from ratepayers. The information presented is not intended or suitable for any other purpose.

Mercer has prepared this report exclusively for the Company; subject to this limitation, the Company may direct that this report be provided as evidence in connection with the rate recovery application to the OEB. Mercer is not responsible for use of this report by any other party.

This report may not be used for any other purpose. Mercer is not responsible for the consequences of any unauthorized use. Its content may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission.

2 Background Information

Determination of Accrual Costs

The EI RPP, EGD RPP, and Pension Choices Plan have defined contribution ("DC") components as well as defined benefit ("DB") components. The results presented in this report consider both components. The EI RPP, EGD RPP, Pension Choices Plan, and Legacy Spectra Closed Plans are funded by contributions from the Company unless it elects to use a funding excess to meet annual contribution requirements. The EI RPP and Pension Choices Plan are also partially funded by contributions from plan members. Pension benefits payable from the defined benefit components are based on length of service and final average earnings and, for the EGD RPP, EGD SERP and EGD SSERP, and for pre-2018 benefits in the EGD RPP, EI RPP and EI SPP are partially indexed for inflation after retirement.

In 2022, Enbridge Inc. decided to merge all past service benefits from the Legacy Spectra Closed Plans into the EI RPP. In connection with these amendments, Enbridge Inc. will apply to transfer the assets and liabilities for all members into the EI RPP. The asset transfer and amendment will be subject to regulatory approval. These asset transfer applications and amendments have not yet been filed with the applicable pension regulator. Therefore, these pending transactions have not been reflected in these results (i.e., the Legacy Spectra Closed Plan is determined independently from EI RPP). Reflecting the transaction would not have an impact on the aggregate of these results.

The EI SPP is funded by contributions from Enbridge unless it elects to use a funding excess to meet annual contribution requirements. There are EI SPP assets in trust for some members who are US taxpayers working in Canada identified as Canadian Grantor Trust assets ("CGT"). Due to tax regulations/implications in the US, the assets backing these members' supplemental benefits cannot be restricted. Therefore, these assets are excluded for the purposes of determining accrual costs. Pension benefits are based on length of service and final average earnings and are partially indexed for inflation after retirement for pre-2018 benefits.

The EGD SERP and the EGD SSERP are closed supplemental plans, funded by contributions from Enbridge in accordance with its funding policy. Pension benefits are based on length of service and final average earnings and are partially indexed for inflation after retirement. There are no longer any active members in either plan.

The LSE SERP is an unfunded arrangement which provides pension benefits in excess of the maximum pension limits imposed under the *Income Tax Act* based on the provisions of the Legacy Spectra Plans.

The EGD and Spectra OPEB Plans are unfunded benefit plans providing for Life Insurance, Medical, Dental and Health Spending Accounts to employees meeting eligibility conditions at retirement.

Accounting Standards and Methodology

Actuarial valuations of the plans on a financial reporting basis have been prepared as at December 31, 2021 or January 1, 2022. These valuations have been extrapolated forward and are the basis for the financial reporting projections contained herein.

The Company's fiscal year end date is December 31, and the measurement date for plan assets and obligations as described in this report is December 31.

Results contained in this report that relate to accrual costs are in accordance with accounting principles generally accepted in the United States of America ("US GAAP") for publicly traded entities.

All results presented in this report are in Canadian dollars.

Additional details on the accounting assumptions and methodology used in these projections are provided in Appendix C.

Funding Standards and Methodology

Actuarial valuations of the plans on a statutory reporting basis have been prepared as at December 31, 2021 or January 1, 2022. These valuations have been extrapolated forward and are the basis for the funding projections contained herein.

The EI RPP is currently a federally registered pension plan and subject to the minimum funding requirements of the *Pension Benefits Standards Act, 1985.* The EGD RPP, Pension Choices Plan, and Legacy Spectra Closed Plans are Ontario registered pension plans and subject to the minimum funding requirements of the *Pension Benefits Act (Ontario)*. The EGD SERP, EGD SSERP and EI SPP are supplemental pension plans and funded in accordance with Enbridge Inc.'s Funding Policy and plan documents. The LSE SERP is an unfunded arrangement and Enbridge pays pensions in-pay from Company revenues.

The plurality (majority) of the EI RPP's membership shifted to Ontario with the regulatory filing effective December 31, 2019. In accordance with the Multi-Jurisdictional Pension Plan Agreement, the jurisdiction of the EI RPP will change to the Financial Services Regulatory Authority of Ontario no later than December 26, 2022, which the Office of the Superintendent of Financial Institutions has confirmed. Following this change, the funding requirements of the *Pension Benefits Act (Ontario)* and regulations will apply to the EI RPP. We have reflected this change in jurisdiction in calculating the cash funding requirements of the EI RPP commencing on and after December 31, 2022.

DB current service costs are determined on a going concern basis. We have extrapolated the going concern service costs, where applicable, from 2022 to 2024 in order to determine this element of cash funding requirements. The Company is also required to fund any deficits that exist on a going concern basis. All plans are expected to have a going concern funding excess as at December 31, 2022 based on the economic conditions as at April 30, 2022.

Under Ontario funding requirements, solvency deficit funding is required if a plan's solvency ratio is less than 85%. All Ontario plans are expected to exceed an 85% solvency ratio as at December 31, 2022 based on the economic conditions as at April 30, 2022.

Future Valuations

Mercer has prepared this future valuation analysis for the purposes of determining the Company's share of accrual costs and cash funding requirements over 2022 to 2024.

The future valuations included in this presentation are based on membership data as at December 31, 2021/or January 1, 2022. For the EI RPP and EGD RPP, the plan populations are extrapolated into the future based on economic and demographic assumptions as at April 30, 2022 along with expected future benefit accruals. Actuarial valuations are performed at each year-end to estimate the plan obligations at that time. For the Pension Choices, Legacy Closed Plans, EGD SERP, EGD SSERP, LSE SERP, and EI SPP, a valuation based on membership data as at December 31, 2021 and assumptions as at April 30, 2022 has been performed. To project the plans' obligations at future dates, the obligations are adjusted for expected additional benefit accruals (if applicable), benefit payments, and interest. For all plans, these projected obligations are combined with assets which are also projected to each yearend to calculate the funding and accounting requirements that might exist under the current applicable funding regulations or requirements and accounting standards at each future valuation date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this presentation. As well, actuarial assumptions are used to project the population to each future valuation date based on a single scenario. However, the future is uncertain and the plans' actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future, and other factors.

We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes, and the results are sensitive to all the assumptions used in the valuation.

3

Financial Results

Projected Future accrual costs

We have projected the results of the December 31, 2021 / January 1, 2022 actuarial valuations of the plans for financial reporting purposes forward to each of the years ending 2022 through 2023. The purpose of these projections is to estimate the accounting costs for 2023 through 2024. The projections are based on the economic environment as at April 30, 2022 and assumptions described in Appendix C. **The actual economic environment as at each of the years ending 2022 through 2023 and actual plan experience over this period may differ significantly from these assumptions.**

The projected balance sheet and accumulated other comprehensive income for the fiscal years ending 2021 to 2023 are summarized below.

Company's Share US GAAP ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried	Group 1	Group 3
December 31, 2021								
Fair value of plan assets	161,408	1,187,366	578,449	179,522	169,633	75,041	10,492	10,678
Benefit obligation	211,785	1,097,187	605,735	156,840	139,053	61,785	9,023	8,371
Funded status (plan assets less benefit obligations)	**(50,377)**	**90,179**	**(27,286)**	**22,682**	**30,580**	**13,256**	**1,468**	**2,308**
Prior service credit (cost)	-	-	-	-	-	-	-	-
Net gain (loss)	13,618	(214,077)	(55,476)	(3,051)	(1,276)	(2,320)	(226)	(440)
Accumulated other comprehensive income (loss)	13,618	(214,077)	(55,476)	(3,051)	(1,276)	(2,320)	(226)	(440)
Accumulated contributions in excess of net periodic benefit cost	(63,995)	304,256	28,191	25,733	31,856	15,576	1,694	2,748
Net amount [surplus (deficit)] recognized in statement of financial position	(50,377)	90,179	(27,286)	22,682	30,580	13,256	1,468	2,308
December 31, 2022								
Fair value of plan assets	210,464	1,166,110	557,928	164,778	156,141	68,923	9,851	10,034
Benefit obligation	202,964	891,551	468,693	129,297	112,504	50,408	7,248	6,622
Funded status (plan assets less benefit obligations)	**7,500**	**274,560**	**89,235**	**35,481**	**43,638**	**18,515**	**2,603**	**3,412**
Prior service credit (cost)	-	-	-	-	-	-	-	-
Net gain (loss)	83,484	(63,984)	40,607	4,695	6,952	812	624	352
Accumulated other comprehensive income (loss)	83,484	(63,984)	40,607	4,695	6,952	812	624	352
Accumulated contributions in excess of net periodic benefit cost	(75,984)	338,543	48,628	30,786	36,685	17,703	1,978	3,060
Net amount [surplus (deficit)] recognized in statement of financial position	7,500	274,560	89,235	35,481	43,638	18,515	2,603	3,412
December 31, 2023								
Fair value of plan assets	235,224	1,193,870	569,833	162,994	155,019	68,314	9,868	10,092
Benefit obligation	251,965	883,968	465,380	124,399	108,143	48,402	7,072	6,445
Funded status (plan assets less benefit obligations)	**(16,741)**	**309,902**	**104,452**	**38,595**	**46,876**	**19,912**	**2,796**	**3,647**
Prior service credit (cost)	-	-	-	-	-	-	-	-
Net gain (loss)	85,753	(66,594)	38,692	4,295	6,432	580	590	321
Accumulated other comprehensive income (loss)	85,753	(66,594)	38,692	4,295	6,432	580	590	321
Accumulated contributions in excess of net periodic benefit cost	(102,495)	376,495	65,761	34,300	40,444	19,332	2,206	3,326
Net amount [surplus (deficit)] recognized in statement of financial position	(16,741)	309,902	104,452	38,595	46,876	19,912	2,796	3,647

Company's Share US GAAP ('000s)	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
December 31, 2021							
Fair value of plan assets	14,927	8,075	19,766	-	-	2,415,357	2,415,357
Benefit obligation	14,815	3,438	22,371	54,968	156,706	2,385,371	2,542,077
Funded status (plan assets less benefit obligations)	**113**	**4,638**	**(2,605)**	**(54,968)**	**(156,706)**	**29,988**	**(126,718)**
Prior service credit (cost)	-	-	-	-	(275)	-	(275)
Net gain (loss)	(4,197)	22	(389)	(11,867)	12,038	(279,679)	(267,641)
Accumulated other comprehensive income (loss)	(4,197)	22	(389)	(11,867)	11,763	(279,679)	(267,916)
Accumulated contributions in excess of net periodic benefit cost	4,309	4,616	(2,215)	(43,101)	(168,469)	309,668	141,199
Net amount [surplus (deficit)] recognized in statement of financial position	113	4,638	(2,605)	(54,968)	(156,706)	29,988	(126,718)
December 31, 2022							
Fair value of plan assets	14,458	7,832	18,698	-	-	2,385,217	2,385,217
Benefit obligation	12,364	2,971	19,060	44,307	124,285	1,947,989	2,072,274
Funded status (plan assets less benefit obligations)	**2,094**	**4,860**	**(362)**	**(44,307)**	**(124,285)**	**437,229**	**312,944**
Prior service credit (cost)	-	-	-	-	(301)	-	(301)
Net gain (loss)	(2,117)	73	2,777	(2,748)	42,581	71,527	114,108
Accumulated other comprehensive income (loss)	(2,117)	73	2,777	(2,748)	42,280	71,527	113,807
Accumulated contributions in excess of net periodic benefit cost	4,211	4,788	(3,140)	(41,559)	(166,565)	365,699	199,134
Net amount [surplus (deficit)] recognized in statement of financial position	2,094	4,860	(362)	(44,307)	(124,285)	437,229	312,944
December 31, 2023							
Fair value of plan assets	13,824	7,674	19,714	-	-	2,446,426	2,446,426
Benefit obligation	11,843	2,688	20,159	43,417	124,391	1,973,881	2,098,272
Funded status (plan assets less benefit obligations)	**1,982**	**4,986**	**(446)**	**(43,417)**	**(124,391)**	**472,544**	**348,153**
Prior service credit (cost)	-	-	-	-	(327)	-	(327)
Net gain (loss)	(2,111)	60	2,685	(2,945)	38,890	67,758	106,648
Accumulated other comprehensive income (loss)	(2,111)	60	2,685	(2,945)	38,563	67,758	106,321
Accumulated contributions in excess of net periodic benefit cost	4,093	4,927	(3,131)	(40,472)	(162,954)	404,786	241,832
Net amount [surplus (deficit)] recognized in statement of financial position	1,982	4,986	(446)	(43,417)	(124,391)	472,544	348,153

Based on the projected financial positions, the resulting US GAAP accrual costs for the plans over 2022 – 2024 are summarized below.

Company's Share US GAAP ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried	Group 1	Group 3
2022								
DB Current service cost (employer)	52,553	6,245	208	-	-	-	-	-
Interest cost	6,479	29,493	16,708	3,877	3,406	1,515	207	188
Expected return on plan assets	(13,139)	(77,801)	(37,320)	(8,706)	(8,235)	(3,643)	(491)	(500)
Amortization of past service costs	-	-	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	-	7,775	-	-	-	-	-	-
Total DB Net Periodic Benefit Cost	45,893	(34,288)	(20,404)	(4,829)	(4,829)	(2,128)	(284)	(312)
DC Current Service Cost	2,539	69	248	-	-	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**48,432**	**(34,219)**	**(20,156)**	**(4,829)**	**(4,829)**	**(2,128)**	**(284)**	**(312)**
2023								
DB Current service cost (employer)	33,678	3,740	138	-	-	-	-	-
Interest cost	9,630	39,215	20,866	5,414	4,716	2,110	310	282
Expected return on plan assets	(16,316)	(80,907)	(38,137)	(8,928)	(8,475)	(3,738)	(537)	(548)
Amortization of past service costs	-	-	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	(481)	-	-	-	-	-	-	-
Total DB Net Periodic Benefit Cost	26,511	(37,952)	(17,133)	(3,514)	(3,759)	(1,628)	(227)	(266)
DC Current Service Cost	3,409	72	229	-	-	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**29,920**	**(37,880)**	**(16,904)**	**(3,514)**	**(3,759)**	**(1,628)**	**(227)**	**(266)**
2024								
DB Current service cost (employer)	33,300	3,677	134	-	-	-	-	-
Interest cost	11,943	38,772	20,674	5,194	4,516	2,018	301	273
Expected return on plan assets	(18,143)	(82,847)	(38,964)	(8,832)	(8,417)	(3,706)	(538)	(551)
Amortization of past service costs	-	-	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	(131)	-	-	-	-	-	-	-
Total DB Net Periodic Benefit Cost	26,969	(40,398)	(18,156)	(3,638)	(3,901)	(1,688)	(237)	(278)
DC Current Service Cost	4,149	74	211	-	-	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**31,118**	**(40,324)**	**(17,945)**	**(3,638)**	**(3,901)**	**(1,688)**	**(237)**	**(278)**

Company's Share US GAAP ('000s)	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
2022							
DB Current service cost (employer)	-	-	1,212	-	1,833	60,218	62,051
Interest cost	311	56	631	1,440	4,252	64,311	68,563
Expected return on plan assets	(417)	(228)	(932)	-	-	(151,412)	(151,412)
Amortization of past service costs	-	-	-	-	(26)	-	(26)
Amortization of net actuarial loss (gain)	204	-	12	38	(923)	8,029	7,106
Total DB Net Periodic Benefit Cost	98	(172)	923	1,478	5,136	(18,854)	(13,718)
DC Current Service Cost	-	-	-	-	-	2,856	2,856
Total (DB & DC) Net Periodic Benefit Cost	**98**	**(172)**	**923**	**1,478**	**5,136**	**(15,998)**	**(10,862)**
2023							
DB Current service cost (employer)	-	-	924	-	1,187	38,480	39,667
Interest cost	514	113	864	1,923	5,511	85,957	91,468
Expected return on plan assets	(459)	(252)	(955)	-	-	(159,252)	(159,252)
Amortization of past service costs	-	-	-	-	(26)	-	(26)
Amortization of net actuarial loss (gain)	64	-	-	-	(3,212)	(417)	(3,629)
Total DB Net Periodic Benefit Cost	119	(139)	833	1,923	3,460	(35,232)	(31,772)
DC Current Service Cost	-	-	-	-	-	3,710	3,710
Total (DB & DC) Net Periodic Benefit Cost	**119**	**(139)**	**833**	**1,923**	**3,460**	**(31,522)**	**(28,062)**
2024							
DB Current service cost (employer)	-	-	949	-	1,187	38,060	39,247
Interest cost	490	101	911	1,878	5,514	87,071	92,585
Expected return on plan assets	(438)	(247)	(1,006)	-	-	(163,689)	(163,689)
Amortization of past service costs	-	-	-	-	(26)	-	(26)
Amortization of net actuarial loss (gain)	76	-	-	-	(2,964)	(55)	(3,019)
Total DB Net Periodic Benefit Cost	128	(146)	854	1,878	3,711	(38,613)	(34,902)
DC Current Service Cost	-	-	-	-	-	4,434	4,434
Total (DB & DC) Net Periodic Benefit Cost	**128**	**(146)**	**854**	**1,878**	**3,711**	**(34,179)**	**(30,468)**

Projected Future Cash

We have projected the results of the December 31, 2021 / January 1, 2022 actuarial valuations of the plans for funding purposes forward to each of the years ending 2023 through 2024. The purposes of these projections is to estimate the Company's share of the minimum cash funding requirements of the plans for 2022 through 2024. The projections are based on the economic environment as at April 30, 2022 and assumptions described in Appendix D and Appendix E. **The actual economic environment as at each of the years ending 2022 through 2023 and actual plan experience over this period may differ significantly from these assumptions.**

Based on the projected going concern and solvency positions, the resulting minimum funding requirements for the plans over 2022 – 2024 are summarized below.

Company's Share Projected Contributions ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried	Group 1	Group 3
2022								
DB Current Service Cost	24,781	-	33	-	-	-	-	-
DC Current Service Cost	2,539	69	248	-	-	-	-	-
Going Concern Special Payments	-	-	-	-	-	-	-	-
Solvency Special Payments	9,124	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	-	-	-
Total	**36,444**	**69**	**281**	**-**	**-**	**-**	**-**	**-**
2023								
DB Current Service Cost	-	-	-	-	-	-	-	-
DC Current Service Cost	3,409	72	229	-	-	-	-	-
Going Concern Special Payments	-	-	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	-	-	-
Total	**3,409**	**72**	**229**	**-**	**-**	**-**	**-**	**-**
2024								
DB Current Service Cost	-	-	-	-	-	-	-	-
DC Current Service Cost	4,149	74	211	-	-	-	-	-
Going Concern Special Payments	-	-	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	-	-	-
Total	**4,149**	**74**	**211**	**-**	**-**	**-**	**-**	**-**

Company's Share Projected Contributions ('000s)	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
2022							
DB Current Service Cost	-	-	-	-	-	24,814	24,814
DC Current Service Cost	-	-	-	-	-	2,856	2,856
Going Concern Special Payments	-	-	64	-	-	64	64
Solvency Special Payments	-	-	-	-	-	9,124	9,124
Direct Benefit Payments	-	-	-	3,020	7,040	3,020	10,060
Total	**-**	**-**	**64**	**3,020**	**7,040**	**39,878**	**46,918**
2023							
DB Current Service Cost	-	-	842	-	-	842	842
DC Current Service Cost	-	-	-	-	-	3,710	3,710
Going Concern Special Payments	-	-	54	-	-	54	54
Solvency Special Payments	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	3,009	7,071	3,009	10,080
Total	**-**	**-**	**896**	**3,009**	**7,071**	**7,615**	**14,686**
2024							
DB Current Service Cost	-	-	912	-	-	912	912
DC Current Service Cost	-	-	-	-	-	4,434	4,434
Going Concern Special Payments	-	-	59	-	-	59	59
Solvency Special Payments	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	3,014	7,134	3,014	10,148
Total	**-**	**-**	**971**	**3,014**	**7,134**	**8,419**	**15,553**

Important Notice

The results shown in this report include projections of plan assets, plan liabilities, contribution requirements, and cash flows to a date that is after the calculation date of this report. Such projections are sensitive to many factors that are unknowable at this time, including (but not limited to) the level of market interest rates, investment performance on the pension fund to the projection date, and other plan demographic and economic experience over the projection period. As a result, actual plan assets, plan liabilities, contribution requirements, and cash flows in future years will be different from those projected and these differences may be significant or material. *Factors such as plan amendments, legislative changes or changes in accounting standards may also be relevant in some cases.*

4

Actuarial Opinion

This report was prepared in accordance with generally accepted actuarial principles and procedures. The actuarial assumptions for financial reporting were selected by the Company upon the advice of the actuary. We believe that the actuarial assumptions are reasonable for the purposes described in this report.

The rationale for significant financial reporting assumptions which we assisted in selecting is summarized in the actuarial assumptions section of this report.

The Company is ultimately responsible for selecting the accounting policies, methods and assumptions. This information is referenced or described in this report. The Company is solely responsible for communicating to Mercer any changes required to those policies, methods and assumptions.

The Company is solely responsible for selecting the investment policies, asset allocations and individual investments of the funded plans. The Mercer actuaries who prepared this report have not provided any investment advice to the Company.

In our opinion, for the purposes of the calculations and projections,

- The membership data are sufficient and reliable;
- The assumptions are appropriate; and
- The methods employed are appropriate.

The financial reporting calculations have been made in accordance with the requirements of US accounting standards (US GAAP), reflecting application of the Company's accounting policies described in this report.

The funding calculations for the EI RPP have been made in accordance with the requirements of the funding and solvency standards set by the *Pension Benefits Act (Ontario)*, reflecting application of the Company's funding policies described in this report.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are available to answer any questions on the material contained in this report, or to provide explanations or further details as may be appropriate. Collectively, the undersigned credentialed actuaries meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinion with respect to the financial reporting projections contained in this report. We are not aware of any direct or material indirect financial interest or relationship, including investments or other services that could create a conflict of interest that would impair the objectivity of our work.

Scott Thompson, FCIA, FSA

May 24, 2022

Date

Edith Samuels, FCIA, FSA

May 24, 2022

Date

Jesse Little, FCIA, FSA

May 24, 2022

Date

Ken Chin, FCIA, FSA

May 24, 2022

Date

Appendix A
Required Disclosures

Terms of Engagement

In accordance with our terms of engagement with the Company, our projections are based on the following material terms:

- The only purposes of this report are to present actuarial estimates of pension and benefit accrual costs in accordance with US GAAP and the cash funding requirements for 2022 to 2024 for the plans in which the Company participates. We understand this report may be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery of pension and benefit costs from ratepayers. This information presented is not intended or suitable for any other purpose.
- The projections and calculations of costs have been prepared in accordance with US accounting standards (US GAAP). They are based on methods, assumptions and accounting policies selected by Management.
- We have projected assets forward using actual asset returns (net of expenses) to March 31, 2022 and the Company's best estimate of asset returns (net of expenses) after March 31, 2022. Projected future cash flows have also been incorporated.
- We have projected benefit obligations forward using the expected cost of benefits accruing over 2022 through 2024, reflecting interest over each period and adjusting year-end 2021 benefit obligations to reflect the economic environment as at April 30, 2022. Benefit obligations in future periods are projected forward with these same April 30, 2022 assumptions and methodology. Projected future cash flows have also been incorporated.
- The starting point for our asset projection was the market value of assets as of March 31, 2022, described in Appendix B.
- Our accounting calculations are based on the assumptions and methodology described in Appendix C. The discount rate assumption reflects market conditions as at April 30, 2022 and the Mercer Model discount rate methodology. The expected return on assets is based on Mercer's capital market assumptions as at March 31, 2022.
- Our funding calculations are based on the assumptions and methodology described in Appendix D and Appendix E. The discount rate assumption and provision for adverse deviation reflects market conditions as at March 31, 2022.
- Our calculations are based on extrapolations of valuations performed using membership data as at December 31, 2021 or January 1, 2022 for the pension plans and January 1, 2021 for the OPEB plans. The membership data used in our projections and calculations is summarized in Appendix F.

- Our calculations reflect the provisions of the plans as at April 30, 2022. Based on the information provided by the Company, no substantive amendments other than those described in Section 2 have been made to the plans since that date. A summary of the plans' provisions is provided in Appendix G.

Subsequent Events

As indicated in the Introduction, we have anticipated the EI RPP regulatory jurisdiction change and its implications for cash funding with effect from December 31, 2022. After checking with representatives of the Company, to the best of our knowledge there have been no other events subsequent to April 30, 2022 which, in our opinion, would have a material impact on the results of the projections.

Appendix B

Plan Assets

The DB pension funds of the plans are held by CIBC Mellon. The EGD SERP, EGD SSERP, and EI SPP assets also include the refundable tax accounts held with CRA. In preparing this report, we have relied upon fund statements as at March 31, 2022 prepared by CIBC Mellon without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

The starting point for our projections of assets were the market value of each plans' assets as at March 31, 2022.

Investment Policy

The plan administrator has adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk that is consistent with the pension plans' investment objectives. A significant component of this investment policy is the asset mix.

The plan administrator is solely responsible for selecting the pension plans' investment policies, asset allocations, and individual investments.

The constraints on the asset mix at the valuation date, as provided to us by the Company, are shown for information purposes.

	Investment Policy Target				
	EI RPP	EGD RPP and Pension Choices Plan	Legacy Spectra Closed Plans	EI SPP[1]	EGD SERP and EGD SSERP[2]
Canadian equities	10.0%	10.0%	9.0%	15.0%	25.0%
Foreign equities	35.0%	30.0%	31.0%	55.0%	45.0%
Private equity	7.5%	6.0%	0.0%	7.5%	0.0%
Canadian bonds	14.0%	20.0%	60.0%	20.0%	30.0%
Real return bonds	6.0%	10.0%	0.0%	10.0%	0.0%
Private debt	7.5%	6.0%	0.0%	0.0%	0.0%
Infrastructure	10.0%	9.0%	0.0%	0.0%	0.0%
Real estate	10.0%	9.0%	0.0%	0.0%	0.0%
Cash and cash equivalents	0.0%	0.0%	0.0%	0.0%	0.0%
	100.0%	100.0%	100.0%	100.0%	100.0%

[1] As a percentage of total assets including the refundable tax account.

[2] As a percentage of the invested assets. 50% of the total plan assets are in a refundable tax account held by Canada Revenue Agency.

The EI SPP target allocations may be achieved by physical investments or futures contracts. A portion of the physical investments will be made in cash instruments which will serve as collateral for the futures contracts.

Because the plans' assets (which are invested in accordance with the above investment policy) are not matched to the plans' liabilities (which tend to behave like long bonds), the plans' financial position will fluctuate over time. These fluctuations could be significant and could cause the plans to become underfunded or overfunded even if the Company contributes to the plans based on applicable minimum funding requirements.

Appendix C

Methods and Assumptions – Accounting

Valuation of Assets

For this valuation, we have used the market value of assets, extrapolated as follows.

For purposes of these estimates, we have projected the market values to each year end. In 2022, we have reflected the actual investment experience from January 1, 2022 to March 31, 2022, and projected the assets to December 31, 2022 using the Company's best estimates of asset returns (net of all expenses) from April 1, 2022 to December 31, 2022. For 2023, we have used the Company's best estimates of annual net asset returns. The rates of return reflected in our projections are as follows:

	Actual asset return (net of all expenses)	Estimated asset return (net of all expenses)	
Plan	From January 1, 2022 to March 31, 2022	From April 1, 2022 to December 31, 2022	Annual estimated returns after December 31, 2022
EI RPP	-2.71%	5.60%	7.60%
EGD RPP	-2.19%	5.28%	7.10%
Pension Choices	-3.13%	5.21%	7.00%
EI SPP	-4.29%	3.80%	5.10%
M&S Plan	-2.41%	4.22%	5.60%
Salaried Plan	-2.41%	4.22%	5.60%
BU Plan	-2.40%	4.22%	5.60%
G1 Plan	-2.39%	4.22%	5.60%
G3 Plan	-2.39%	4.22%	5.60%
EGD SERP	-2.14%	2.48%	3.30%
EGD SSERP	-2.16%	2.48%	3.30%

Estimated future cash flows, including minimum funding contributions have been incorporated into our projections.

Actual assets over year-ends 2022 through 2023 will differ from these estimates.

Valuation of Benefit Obligations and Current Service Cost

Benefit obligations are estimated using the Projected Unit Credit method. Under this method each participant's benefits under the plan are attributed to years of service, taking into consideration future salary increases and the plan's benefit allocation formula. Thus, the estimated total pension to which each participant is expected to become entitled at retirement is broken down into units, each associated with a year of past or future credited service.

A description of the calculation follows:

- An individual's estimated attributed benefit for valuation purposes related to a particular separation date (for example, expected date of retirement, leaving service or death) is the benefit described under the plan based on credited service as at the measurement date, but determined using the projected salary that would be used in the calculation estimate of the benefit on the expected separation date.
- For the OPEB plans, an individual's estimated accrued benefit for valuation purposes is the projected benefit at full eligibility date, or current age if later, multiplied by the ratio of service at the valuation date over service at full eligibility date. Service for this purpose is measured from date of hire.
- The benefit attributed to an individual's service during a plan year is the excess of the attributed benefit for valuation purposes at the end of the plan year over the attributed benefit for valuation purposes at the beginning of the plan year. Both attributed benefits are estimated from the same projections to the various anticipated separation dates.
- An individual's estimated benefit obligation is the present value of the attributed benefit for valuation purposes at the beginning of the plan year, and the service cost is the present value of the benefit attributed to the year of service in the plan year. If multiple decrements are used, the benefit obligation and the service cost for an individual are the sum of the component benefit obligations and service costs associated with the various anticipated separation dates. Such benefit obligations and service costs reflect the estimated attributed benefits and the probability of the individual separating on those dates.

In all cases, the benefit obligation is the total present value of the individuals' attributed benefits for valuation purposes at the measurement date, and the service cost is the total present value of the individuals' benefits attributable to service during the year. If multiple decrements are used, the present values take into account the probability of the individual leaving employment at the various anticipated separation dates.

Valuation Procedures

The valuation procedures are as described in Section 2 of this report.

Accounting Policies

The accounting policies in cases where Enbridge has a choice of policy are set out below.

Materiality threshold: Enbridge has not instructed us to make any adjustments to the valuation procedures described in order to satisfy its materiality threshold.

Net periodic benefit cost measurement: The net periodic benefit cost charged to profit or loss is budgeted for at the start of each reporting period using actuarial assumptions fixed at the start of the period, including assumptions about expected pensionable salaries, contributions and benefit payments that will be made during the period. It is only updated to allow for subsequent experience in the event of material changes.

Interest on service cost: The current service cost includes all interest on the service cost during the reporting period.

Administration expenses: An allowance for administration expenses is included in the pension expense by making a deduction from the expected rate of return on plan assets.

Discretionary benefits: The benefit obligation for the EI RPP includes a reserve for the discretionary benefits associated with the early retirement subsidies in the plan that are subject to the consent of Enbridge, on the grounds that these consent benefits form a substantive commitment.

Significant events: There were no significant events that occurred during the reporting period that required accounting policy decisions.

Amortization method and periods: The cumulative gains and losses in excess of 10% of the greater of the beginning of year benefit obligation or market related value of plan assets are amortized over the expected average remaining working lives of the employees participating in the plan for active plans. For plans that are largely or fully inactive, the amortization period is the expected average remaining lifetime of the members of the plan

For EGD OPEB plans, any cumulative gains and losses in excess of 10% of the greater of the beginning of year benefit obligation that is amortized over the expected average remaining working lives of the employees participating in the plans are reallocated between each plan based on their respective proportion of their beginning of year benefit obligation.

For Spectra OPEB plans, any cumulative gains and losses in excess of 10% of the greater of the beginning of year benefit obligation that is amortized over the expected average remaining working lives of the employees participating in the plans are reallocated between each plan based on their respective proportion of their beginning of year benefit obligation.

Past service costs: Enbridge has elected to amortize past service costs resulting from plan amendments on a linear basis over the average remaining service period of active members expected to receive benefits under the plan.

Actuarial Estimates

Discount rate setting process: The effective discount rate on the benefit obligations is estimated as the single equivalent rate such that the present value of the benefit obligations cash flows using the single rate equals the present value of those cash flows using the Mercer Yield Curve as of the measurement date.

The same process is applied to the service cost cash flows to determine the effective discount rate associated with the service cost. Separate effective discount rates are determined for the benefit obligations and service costs.

Determination of benefit obligations and service costs: The benefit obligations are determined by discounting each cash flow using the spot rates from the Mercer Yield Curve as of the measurement date.

Calculation of interest: Interest on benefit obligations, for purposes of determining the interest cost, and the interest on the service cost are calculated by applying interest to the present value of the cash flows expected at each payment date. For this purpose, interest is determined using the same spot rate used to determine the present value of the associated payment.

Actuarial Assumptions

The assumptions as at the reporting date are used to determine the present value of the benefit obligation at that date and the net periodic benefit cost for the following year. The assumptions as at December 31, 2021 are those used by Enbridge for financial reporting purposes. Any changes to assumptions after December 31, 2021 are due to changes in the economic environment. The principal financial and demographic assumptions used in our projections are shown in the table below:

Assumptions	For projected December 31, 2022 and 2023 year-ends and the following year's expense		As at December 31, 2021 year-end and the following year's expense	
Discount rates:	Effective discount rate for benefit obligations	Effective rate of interest on benefit obligations	Effective discount rate for benefit obligations	Effective rate of interest on benefit obligations
• EGD RPP	4.91%	4.54%	3.19%	2.54%
• EI RPP	4.99%	4.67%	3.28%	2.93%
• EI SPP	4.92%	4.58%	3.20%	2.80%
• Pension Choices Plan	4.93%	4.57%	3.23%	2.81%
• M&S Plan	4.71%	4.37%	3.04%	2.56%
• BU Plan	4.78%	4.38%	3.01%	2.54%
• Salaried Plan	4.78%	4.37%	3.02%	2.54%
• G1 Plan	4.82%	4.44%	2.98%	2.36%
• G3 Plan	4.81%	4.42%	2.95%	2.32%
• EGD SERP	4.75%	4.35%	2.82%	2.18%
• EGD SSERP	4.43%	4.08%	2.27%	1.74%
• LSE SERP	4.82%	4.43%	3.07%	2.61%
• EGD OPEB	4.93%	4.58%	3.21%	2.80%

Assumptions	For projected December 31, 2022 and 2023 year-ends and the following year's expense		As at December 31, 2021 year-end and the following year's expense	
• Spectra OPEB	4.90%	4.54%	3.17%	2.74%
Discount rates:	Effective discount rate for current service cost	Effective rate of interest on current service cost	Effective discount rate for current service cost	Effective rate of interest on current service cost
• EGD RPP	5.08%	4.92%	3.50%	3.05%
• EI RPP	5.06%	4.83%	3.38%	3.13%
• EI SPP	5.02%	4.81%	3.33%	3.11%
• Pension Choices Plan	5.06%	4.91%	3.39%	3.21%
• Legacy Spectra Closed Plans	N/A	N/A	N/A	N/A
• EGD SERP, EGD SSERP and LSE SERP	N/A	N/A	N/A	N/A
• EGD OPEB	5.09%	5.00%	3.41%	3.31%
• Spectra OPEB	5.08%	4.99%	3.41%	3.29%%
Expected long-term rate of return on assets:				
• EGD RPP	7.10% per year		6.70% per year	
• EI RPP	7.60% per year		7.10% per year	
• EI SPP	5.10% per year		4.80% per year	
• Pension Choices Plan	7.00% per year		6.60% per year	
• M&S, Salaried Plan, and BU Plan	5.60% per year		5.00% per year	
• G1 and G3	5.60% per year		4.80% per year	
• EGD SERP & SSERP	3.30% per year		2.90% per year	
Expenses	Implicit in long-term rate of return		Same	
Post-retirement indexation	Based on the contractual indexation provisions of the applicable plan and assumed inflation of 4.50% in 2022, trending down to 2.00% per year for years 2026 and after		Based on the contractual indexation provisions of the applicable plan and assumed inflation of 2.00% per year	
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age		Same	
Bonus load	Variable STIP – 115% + 5%[3] of target Non-Variable STIP – 100% of target		Same	
Target bonus	Individual target bonus		Same	
ITA limit / YMPE increases	2.50%		Same	
Interest on employee contributions	3.00% per year		Same	

[3] The EI RPP, EGD RPP and EI SPP bonus load includes an additional 5% load due to plan provisions where the final average earnings may not be consecutive.

Assumptions	For projected December 31, 2022 and 2023 year-ends and the following year's expense	As at December 31, 2021 year-end and the following year's expense
Mortality table	2014 Private Sector Canadian Pensioners Mortality Table	Same
Mortality improvements	Fully generational using CPM Improvement Scale B	Same
Mortality size adjustment	Nil	Same
Termination rates:		
• EI RPP, EI SPP, EGD RPP, Pension Choices Plan and WEI Plan	Plan specific table. See tables of sample rates at the end of this section	Same
• Legacy Spectra Closed Plans	Nil	Same
Retirement rates	Plan specific table. See tables of sample rates at the end of this section	Same
Form of benefit elected at retirement	100% of eligible members receive a pension	Same
Form of benefit elected at termination:		
• EI SPP	100% of eligible members elect a deferred pension	Same
• EI RPP, EGD RPP, and Pension Choices Plan	40% of eligible members elect a deferred pension and 60% elect a lump sum transfer	Same
Actuarial basis for benefits to be settled through a lump sum:	Discount rate: 3.50% Mortality rates: CPM2014 with fully generational improvements using CPM-B	Same
Eligible spouse at retirement	85%	Same
Spousal age difference	Male two years older than female	Same

Age-Related Tables

Sample rates from the age-related tables are summarized in the following tables:

Termination Rates and Pensionable Earnings Increase Rates

	Termination Rates			Pensionable Earnings Increase Rates
Age	Union	Non-Union Under 5 Years of Service	Non-Union Over 5 Years of Service	
<25	2.0%	5.5%	4.0%	5.00%
25 – 29	2.0%	5.5%	4.0%	5.00%
30 – 34	2.0%	5.5%	4.0%	4.25%
35 – 39	1.5%	5.5%	4.0%	4.25%

Age	Termination Rates			Pensionable Earnings Increase Rates
	Union	Non-Union Under 5 Years of Service	Non-Union Over 5 Years of Service	
40 – 44	1.5%	6.5%	5.0%	3.25%
45 – 49	1.5% grading to 1.1%	8.5%	4.0%	3.25%
50 – 54	1.0%	8.5%	3.0%	2.50%
>55	0.0%	0.0%	0.0%	2.50%

Retirement Rates

Age	Retirement Rates					
	Union Reduced	Union Unreduced	Non-Union East Reduced[4]	Non-Union East Unreduced[5]	Non-Union West Reduced[5]	Non-Union West Unreduced[6]
55	2.5%	20.0%	10.0%	25.0%	15.0%	33.3%
56	2.5%	10.0%	5.0%	12.5%	15.0%	25.0%
57	5.0%	10.0%	5.0%	18.75%	15.0%	25.0%
58	5.0%	20.0%	5.0%	18.75%	15.0%	33.3%
59	5.0%	10.0%	10.0%	18.75%	15.0%	25.0%
60	10.0%	10.0%	15.0%	30.0%	30.0%	30.0%
61	5.0%	15.0%	15.0%	25.0%	25.0%	25.0%
62	n/a	15.0%	n/a	25.0%	n/a	25.0%
63-64	n/a	25.0%	n/a	25.0%	n/a	30.0%
65-70	n/a	40.0%	n/a	40.0%	n/a	40.0%
71	n/a	100.0%	n/a	100.0%	n/a	100.0%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death, or termination of employment, we have taken rates of pay on December 31, 2021 and assumed that such pensionable earnings will increase at the assumed rate on April 1st of each year.

Pensionable Bonuses

Benefits accrued after December 31, 1999 by Senior Management Employees (SMEs), and benefits accrued after June 30, 2001 by non-SMEs are based on base earnings plus 50% of the actual bonuses received by the members. Actual bonuses have been estimated by using the current target bonus rates for all members.

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[4] East means province of employment is New Brunswick, Newfoundland & Labrador, Nova Scotia, Ontario or Quebec.

[5] West means province of employment is Alberta, British Columbia, Manitoba, Northwest Territories or Saskatchewan. Also includes suspended members in the United States.

For employees subject to variable bonuses, the target bonuses described above were increased by:

- 15% to reflect an expectation that an individual's actual bonus at retirement may be higher than the individual's current target bonus due to promotion, and

in the EGD RPP, EI RPP, and EI SPP, an additional 5% (20% total) to reflect that annual bonuses vary from year to year but only the best three out of the last five bonuses are included in the final average earnings calculation.

New Entrants

Upon hire, new non-SMEs must join the defined contribution provision of the EI RPP. After five years of service, they automatically join the defined benefit provision of the plan. In order to estimate the cost of DC benefits in 2022 through 2024, we have assumed that the total payroll (for DB and DC members) will increase by 3.00% per year. As DB members terminate or retire, their payroll is replaced by a DC member.

For the EI SPP, where costs are predominantly driven by the senior managers, we have assumed open and stable population for this group, so no new entrant profile is required.

All other pension plans are closed to new entrants, so no assumption is required.

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate
The discount rate was derived from the Mercer model. The Mercer model is based on actual AA corporate bond yield data for short term yields and extrapolated data for longer terms. Under the Mercer model, the plans' projected benefit payments are matched against a series of spot rates derived from a yield to maturity curve.
Expected Rate of Return on Plan Assets
The expected rate of return on plan assets for each plan is based on: • Values between the 35th percentile and 65th percentile of simulated investment returns using estimated returns and deviations of those returns for each major asset class consistent with market conditions on the valuation date, the expected time horizon over which benefits are expected to be paid, and the target asset mix specified in the plans' investment policy. • Additional returns assumed to be achievable due to active equity management, equal to the fees related to active equity management. Such fees were determined as the difference between the provision for total investment expenses and the hypothetical fees that would be incurred for passive management of all assets. • Implicit provision for investment expenses determined as the expected rate of expenses to be paid from the fund in the future, which reflects the average rate of investment expenses paid from the fund over the last three years. • Implicit provision for non-investment expenses determined as the expected rate of expenses to be paid from the fund in the future, which reflects the average rate of non-investment expenses paid from the fund over the last three years.

Inflation

The inflation assumption takes into consideration projected Canadian inflation rates at elevated levels initially, which will then converge to a 2% long-term equilibrium level by year five. The long-term equilibrium inflation level is based on the mid-point of the Bank of Canada's inflation target range of between 1% and 3%.

Post-Retirement Pension Increases

The assumption is based on the plans' cost of living formulae and inflation assumption above.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings Increases

The assumption is based on historical real economic growth and the underlying inflation assumption. In the five year period where inflation is elevated above 2%, it is assumed that there is a corresponding reduction in the spread for real economic growth due to recent fluctuations caused by COVID-19.

Pensionable Earnings Increases

The pensionable earnings increase rate reflects an age-based merit and promotion scale based on an experience study that was conducted in 2014 considering increases over the years 2009-2013. Over time, results of the experience study have been modified to reflect the Enbridge Inc.'s evolving expectations of pensionable earnings increases.

Bonus Load

The assumption is based on Enbridge Inc. expectations.

Interest on Employee Contributions

The assumption is a best estimate of Government of Canada 5-year personal fixed term interest rates over the period during which interest will be granted on employee contributions, taking into account market conditions on the valuation date and an expectation that rates will rise to a level higher than current historically low levels.

Retirement Rates

The rates of retirement have been developed based on an experience study conducted in 2018 which reviewed the combined experience over the period from 2013 to 2017 of the largest pension plans which the Enbridge Inc. sponsors.

Termination Rates

The rates of termination have been developed based on an experience study conducted in 2018 which reviewed the combined experience over the period from 2013 to 2017 of the largest pension plans which the Enbridge Inc. sponsors.

Mortality Rates

The assumption is based on the Canadian Pensioners' Mortality (CPM) study published by the Canadian Institute of Actuaries in February 2014.

Due to the size of the plans, specific data on plan mortality experience is insufficient to determine the mortality rates. After considering plan-specific characteristics, such as the type of employment, the industry experience, pension and employment income for the plan members, and data in the CPM study, it was determined to use the CPM mortality rates from the private sector without adjustment.

There is broad consensus among actuaries and other longevity experts that mortality improvement will continue in the future, but the degree of future mortality improvement is uncertain. Two mortality improvement scales were recently published by the CIA and may apply to Canadian pension valuations:

- The Canadian Pensioners Mortality (CPM) study published in February 2014 included CPM Improvement Scale B (CPM-B).
- A report released by the Task Force on Mortality Improvement on September 20, 2017 includes an analysis of the rate of mortality improvement for the Canadian population and provides for mortality improvement scale MI-2017 to be considered for the purpose of reflecting future mortality improvement in Canadian actuarial work, while acknowledging that it might be appropriate to use alternative mortality improvement assumptions to reflect the nature of the work.

The CIA Committee on Pension Plan Financial Reporting published a revised version of the Educational Note on the Selection of Mortality Assumptions for Pension Plan Valuations on December 21, 2017. The Educational Note indicates that given the recent publication of the CPM-B and MI-2017 improvement scales and the similar data sets used in their development, it may be appropriate to use either scale in the absence of credible information to the contrary, such as the publication of a successor scale by the CIA.

COVID-19 has impacted mortality rates globally. Statistics Canada reported excess mortality in 2020 for the general Canadian population and other peer countries globally have also seen excess mortality over the course of the pandemic. Mortality experience for the plans have been reflected up to the date of the valuation. We have not adjusted the expected mortality rates for plan members after the valuation date. The long-term implications of the pandemic on mortality rates is unclear as at the date of this report. Credible plan specific experience and relevant broader observed mortality trends after the report date will be reflected in future valuations.

For the valuation, we have used the CPM-B scale, which is a reasonable outlook for future mortality improvement.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

Form of Benefit Elected Upon Termination and Cost of Future Lump Sums

The assumption for form of benefit elected upon termination has been developed based on an experience study conducted in 2018 which reviewed the combined experience over the period from 2013 to 2017 of the largest pension plans which the Company sponsors.

The cost of future lump sums will depend on the level of market interest rates at the time the lump sum is paid and any changes in the applicable actuarial standards for the determination of pension plan commuted values. The assumed cost of future lump sums is based on the average expected level of market interest rates over the period during which lump sums are expected to be paid, taking into account market conditions on the valuation date modified to include a provision for increases in market interest rates to a level higher than current historically low levels. We have also assumed that future lump sums elected by eligible plan participants will be calculated using the mortality basis applicable under the actuarial standards as of the valuation date.

Eligible Spouse

The assumption is based on an experience study conducted in 2018 which reviewed the combined experience over the period from 2013 to 2017 of the largest pension plans which the Enbridge Inc. sponsors.

Spousal Age Difference
The assumption is based on an experience study conducted in 2018 which reviewed the combined experience over the period from 2013 to 2017 of the largest pension plans which the Enbridge Inc. sponsors.
Pre-2018 Consent Benefits
The assumption is consistent with the Enbridge Inc.'s current policies, which are expected to continue in the future.

OPEB-Specific assumptions

All OPEB-specific assumptions used in the projections are consistent with those used by Enbridge for financial reporting as at December 31, 2021.

Health care cost trend rates	
Hospital	4.00% per annum
Prescription drugs	4.00% per annum
Other Medical	4.00% per annum
Vision	4.00% per annum, with an effective 0% per annum net trend rate due to the low fixed dollar limit that exists for the benefit
Retiree HSA	0% per annum
Dental	4.00% per annum
Salary Increase	
EGD OPEB Plan	2.92% per annum
Spectra OPEB Plan	3.00% per annum
Type of coverage	For active members, 85% are assumed to select family coverage at retirement with males assumed to be 2 years older than their female spouses. For current retirees, actual type of coverage and spousal age is assumed.
Age 65 per capita claims excluding administration and taxes	
EGD OPEB Plan – Grandfathered Plan	**As at July 1, 2021**
Hospital	$45
Prescription drugs	$1,312
Other Medical	$211
Vision	$15
Dental	$667
Total	$2,250
	Drug costs are shown before the impact of any provincial drug plan

Spectra OPEB Plan – Union Gas Grandfathered Plan	**As at July 1, 2021**
Hospital	$24
Prescription drugs	$339
Other Medical	$31
Dental	$0 (no more retirees over age 64)
Total	$394
	Drug costs are shown before the impact of any provincial drug plan
Spectra OPEB Plan – Union Gas Common Plan	**As at July 1, 2021**
Prescription drugs	$260
Other Medical	$24
Total	$284
	Drug costs are shown before the impact of any provincial drug plan
Percent of spending account forfeited	
EGD and Harmonized OPEB Plans	15% HCSA
Spectra OPEB Grandfathered Plans	40% RSHSP, 15% HCSA
Utilization (aging factors)	
EGD OPEB Plans	See Table 1
Spectra OPEB Plan	See Table 1
Prescription drug offset	**The following cost offsets were assumed to reflect the impact of provincial drug plans**
EGD and Spectra OPEB Plans except Common Plan	
Quebec	50%
Ontario	65%
Alberta	55%
Prince Edward Island	35%
All other provinces	0%
Spectra Union Gas Common Plans	
All provinces	80%

Administrative expenses as a percentage of paid claims	
Medical	3.25% plus 4.95% for stop loss charge plus applicable taxes
Dental	3.25% plus applicable taxes
Retiree HSA	3.25% plus applicable taxes
Life insurance	1.60% plus applicable taxes
Taxes	
Alberta premium tax	3.00%
Quebec premium	3.30%
Other premium tax	2.00%
Manitoba retail sales tax	7.00%
Quebec retail sales tax	9.00%
Ontario retail sales tax	8.00%

Table 1 – Utilization Rates

Increases in utilization by age					
Attained Age	Hospital	Drug	Other Medical	Dental	Vision
55	45%	75%	106%	106%	106%
60	64%	88%	103%	104%	103%
65	100%	100%	100%	100%	100%
70	161%	109%	102%	95%	97%
75	253%	113%	110%	90%	95%
80	388%	114%	121%	83%	92%

As a general note, assumptions not listed above are the same as those used for the pension plans.

Rationale for OPEB-specific assumptions

A rationale for OPEB-specific assumptions used in the current valuation is provided below.

Health care cost trend rates

The initial healthcare trend rates were estimated based on a combination of plan experience, general market expectations, standards of practice and accepted actuarial practice.

The ultimate healthcare trend rates were estimated based on long-term macroeconomic expectations for per capita GDP growth and GDP inflation. The grading period, which bridges the initial healthcare trend rates to the ultimate, was estimated based on generally accepted expectations for when the proportion of GDP allocated to healthcare reaches its maximum and “resistance” to excess growth in healthcare spending begins.

In March 2018, the Society of Actuaries and the Canadian Institute of Actuaries, in conjunction with McMaster University, published a paper entitled Model of Long-Term Health Care Cost Trends in Canada (the “McMaster Model”). The stated goals of the McMaster Model were to provide, “…a practical means by which actuaries could determine a long-term health care trend rate of growth and to provide guidance on the grading period over which such an ultimate trend is reached.” A national committee of senior health actuaries at Mercer independently reviewed the McMaster Model and found its baseline conclusions of a 4.00% ultimate trend reached in 2040 to be reasonable. Consequently, the ultimate drug trend is 4.00%, to be attained in 2040.

Utilisation (Aging factors)

The utilisation factors are standard factors used by Mercer Canada for non-pension post-retirement medical and dental valuations. These factors were developed based on a large experience study conducted by Mercer Canada.

Claims cost

The per covered member claim costs used in the January 1, 2021 valuation and extrapolated for purposes of determining the liabilities as at December 31, 2021 were based on the actual retiree and dependent claims information for the three year period, January 1, 2018 to December 31, 2020, adjusted with assumed healthcare cost trend rates to July 1, 2021 (mid-point of valuation year). The claims experience was collected and analyzed separately for Hospital, Prescription Drugs, Vision Care, Other Medical and Dental benefits. Furthermore, the 2020 claims experience were adjusted for Dental (+30%) and Other Medical and Vision (+18%) to remove the temporary effect of Covid-19 on claims.

A description of the process used to set the “Age 65 per capita claims costs” is as follows:

- For each plan year (January 1 to December 31) of claims, a cost per covered member was developed by dividing the total annual claims by the total number of eligible retirees and dependents covered during the year.
- This cost per person has been adjusted to the cost per covered member at age 65 based on the individual ages of the covered members using the utilization rates (Table 3).
- The costs are then adjusted with assumed health care cost trend rates from the claims experience year to the midpoint of the valuation year of July 1, 2021.

As indicated, this analysis was performed for each of the three plan years used. The assumed cost per covered member for the valuation was based on a weighted average of the costs for the three plan years with 331/3% weighting given to each of the three plan years.

Health spending account forfeiture percentage

Forfeiture assumptions are based on an analysis of recent claims experience of the spending accounts.

Prescription drug offset due to Provincial drug programs
The prescription drug offset percentages by province are standard Mercer Canada assumptions for post-retiremet medical valuations based on Mercer Canada study. These percentages were developed based on a large experience study conducted by Mercer Canada.
Expenses
Based on the fees charged by the insurer as per the financial arrangement.
Taxes
As legislated by each province.

Appendix D

Methods and Assumptions – Going Concern

Valuation of Assets

For this valuation, we have used the market value of assets adjusted for in-transit amounts, if applicable.

Refer to Appendix C for a summary of the projected asset methodology.

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to be sufficient to meet the plan's cash flow requirements in respect of accrued benefits, absent additional contributions.

As required under the applicable pension benefits act, a funding shortfall must be amortized over no more than a prescribed period through special payments. This prescribed period is 15 years for federally regulated plans and 10 years for Ontario regulated plans. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. However, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, excluding pensionable bonuses, can be expected to remain stable as long as the average age distribution of the group remains constant.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. For the EGD RPP, EI RPP, Pension Choices Plan, and Legacy Spectra Closed Plans at each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. For the EI SPP, EGD SERP, and EGD SSERP, the assumptions used for this valuation are the Company's best estimate assumptions. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

All assumptions on the going concern basis are consistent with those summarized for the accounting basis, with the exception of those described below:

Assumption	Determined as at March 31, 2022
Discount rate:	
• EGD RPP	6.35% per year
• EI RPP	6.65% per year
• EI SPP	5.10% per year
• Pension Choices Plan	6.25% per year
• Legacy Spectra Closed Plans	4.95% per year
• EGD SERP and EGD SSERP	3.30% per year

The assumptions are best-estimate and do not include a margin for adverse deviations.

Provision for Adverse Deviations

The provision for adverse deviations has been established in accordance with Ontario regulations taking into account the following parameters:

Provision for Adverse Deviations	EGD RPP	EI RPP	Pension Choices Plan	Legacy Spectra Closed Plans
i) 5.0% for a closed plan and 4.0% for a plan that is not a closed plan	5.00%	4.00%	5.00%	5.00%
ii) Provision based on combined target asset allocation for non-fixed Income assets	6.00%	4.50%	6.00%	4.00%
iii) Adjustment for expected returns in excess of the Benchmark Discount Rate	2.75%	5.55%	2.66%	0.00%
Provision for Adverse Deviations (i. + ii. + iii.)	13.75%	14.05%	13.66%	9.00%

Rationale for Assumptions

A rationale for the going concern discount rate used in the valuation is provided below.

Discount Rate
We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund, net of investment fees, and less a margin for adverse deviations. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this report. The discount rate is comprised of the following: • Estimated returns for each major asset class consistent with market conditions on the valuation date, modified to include a provision for increases in market interest rates to a level higher than current historically low levels, the expected time horizon over which benefits are expected to be paid, and the target asset mix specified in the plans' investment policy. • Additional returns assumed to be achievable due to active investment management, equal to an estimate of fees related to such active investment management. Such fees were determined by the difference between the provision for total investment expenses and the hypothetical fees that would be incurred for passive management of all assets. • Implicit provision for investment and non-investment expenses determined as the expected rate of expenses to be paid from the fund in the future.

Appendix E

Methods and Assumptions – Hypothetical Wind-Up and Solvency

The following methods and assumptions were only required for determining the projected cash contributions under the EI RPP, as the other plans are either not required or expected to be affected by funding requirements on a solvency or hypothetical wind-up basis.

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with all members fully vested in their accrued benefits.

The circumstances in which the plan wind-up is assumed to have taken place are as follows:

- Enbridge Inc. terminates the plan;
- Membership in the plan ceases on the valuation date; and
- In accordance with the plan provisions on plan termination, no projection of salaries and YMPE are assumed to occur after the valuation date for active and suspended members,

thereby giving rise to the following benefits:

- Active and suspended members not within 10 years of pensionable age (i.e., under the age of 55) are entitled to termination benefits under the Plan;
- Active and suspended members within 10 years of pensionable age (i.e., age 55 and older) are entitled to retirement benefits under the plan; and
- Deferred pensioners, pensioners and survivors are entitled to their accrued vested benefit on the valuation date.

Where applicable, it was assumed that, on plan wind-up:

- The Company would grant consent to early retirement for all active and suspended members age 55 and over.

- Members under age 55 receive the maximum of the minimum benefit required under the Act and a non-indexed pension with Company consent for early retirement.

No benefits payable on plan wind-up under the above postulated scenario were excluded from our calculations.

Upon plan wind-up, members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for March 31, 2022.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

However, there is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. Furthermore, given the size of the plan, it may not be possible to settle the pension via a single group annuity due to the limited availability of indexed and partially indexed annuities in Canada. In accordance with the *Canadian Institute of Actuaries Educational Note Supplement: Guidance for Assumptions for Hypothetical Wind-up and Solvency Valuations Update – Effective March 31, 2022, and Applicable to Valuations with Effective Dates on or after March 31, 2022 and no later than December 30, 2022* (the "Educational Note Supplement"), we have assumed that the settlement of such liabilities would be priced on the same basis as smaller group annuities that are available in the market using the basis as described in the Educational Note Supplement. The actual cost to settle the plan's benefits on wind-up could be materially different.

The Educational Note Supplement provides guidance on estimating the cost of annuity purchases assuming a typical group of annuitants. That is, no adjustments for sub- or super-standard mortality are considered. However, it is expected that insurers will consider plan experience and certain plan-specific characteristics when determining the mortality basis for a particular group. The Educational Note Supplement states that the actuary would be expected to make an adjustment to the regular annuity purchase assumptions where there is demonstrated sub- or super-standard mortality or where an insurer might be expected to assume so. In such cases, the actuary would be expected to make an adjustment to the mortality assumption in a manner consistent with the underlying annuity purchase basis. Given the uncertainty surrounding the actual mortality basis that would be typical of a group annuity purchase, it is reasonable to assume that there is a range of bases that can be expected not to be materially different from the actual mortality basis. Therefore, an adjustment to the regular annuity purchase assumptions would be warranted when the plan's assumed basis falls outside that range.

In this context, we have determined that no adjustment to the mortality rates used in the regular annuity purchase assumptions is required.

We have not included a margin for adverse deviations in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Members	
Lump sum:	70% of active and suspended members under age 55, elect to receive their benefit entitlement in a lump sum.
Annuity purchase:	All remaining members elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Basis for Benefits Assumed to be Settled Through a Lump Sum	
Mortality rates:	100% of the rates of the 2014 Combined Canadian Pensioners Mortality Table (CPM2014) with fully generational improvements using CPM Improvement Scale B
Non-indexed interest rates:	2.70% per year for 10 years, 3.70% per year thereafter
Inflation rates:	1.70% per year for 10 years, 1.70% per year thereafter
Indexation rates:	The above inflation rates are used to determine the contractual post-retirement indexing included in lump sums, reflecting the plan's contractual indexing formula
Basis for Benefits Assumed to be Settled Through the Purchase of an Annuity	
Mortality rates:	100% of the rates of the 2014 Combined Canadian Pensioners Mortality Table (CPM2014) with fully generational improvements using CPM Improvement Scale B
Adjustment to mortality rates:	No adjustment
Non-indexed interest rate:	3.74% per year (based on a duration of 14.3)
Partially-indexed interest rate:	1.94% per year, applicable to benefits subject to contractual post-retirement indexing
Retirement Age	
Maximum value:	Members are assumed to retire at the age which maximizes the value of their entitlement from the EI RPP, based on the eligibility requirements which have been met at the valuation date.
Grow-in:	The benefit entitlement and assumed retirement age of Ontario members whose age plus service equals at least 55 at the valuation date reflect their entitlement to grow into early retirement subsidies and indexation benefits.
Other Assumptions	
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going concern valuation
Maximum pension limit:	$3,420.00 in 2022 increasing at 2.70% per year for 10 years, 2.70% per year thereafter
Termination expenses:	$3,400,000 increasing by 2.00% per year

New entrants are assumed to join the plan consistent with the description in Appendix C.

To determine the hypothetical wind-up position of the EI RPP, a provision has been made for estimated termination expenses payable from the plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the plan and to be charged to the plan.

In addition, termination expenses also include a provision for transaction fees related to the liquidation of the plan's assets and for expenses that may reasonably be expected to be paid by the pension fund under the postulated scenario between the wind-up date and the settlement date. It was assumed for this purpose that the termination process would extend over a two-year period.

Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the plan.

Although the termination expense assumption is a best estimate, actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Effective December 26, 2022, the regulatory jurisdiction of the EI RPP will change to Ontario. We have calculated the funding requirements in accordance with the *Pension Benefits Act (Ontario)* for 2023 to 2024.

Appendix F

Membership Data

Analysis of Membership Data

The actuarial valuations are based on membership data as at December 31, 2021, provided by Enbridge Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest, and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments, and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

The membership data summarized in the following tables is for the total plans. Members employed by the Company are identified by organization data flags supplied by Enbridge Inc.

EI RPP Membership Data

The membership summarized below is for the total plan.

	31.12.2021
Active and Disabled Members Accruing Defined Benefit Service (Non-SMEs)	
Number	5,297
Total base earnings for next year	$586,025,300
Average base earnings for next year	$110,600
Average pensionable earnings for next year	$118,800
Average years of Non-SME DB pensionable service	5.2 years
Average age	44.7 years
Active and Disabled Members Accruing Defined Benefit Service (SMEs)	
Number	227
Total base earnings for next year	$58,053,500
Average base earnings for next year	$255,700
Average pensionable earnings for next year	$314,300
Average years of Non-SME DB pensionable service	3.3 years
Average years of SME DB pensionable service	5.6 years
Average age	50.0 years
Suspended Defined Benefit Members (Non-SMEs)	
Number	235
Total base earnings for next year	$24,023,700
Average base earnings for next year	$102,200
Average pensionable earnings for next year	$106,400
Average years of Non-SME DB pensionable service	5.3 years
Average age	45.5 years
Suspended Defined Benefit Members (SMEs)	
Number	16
Total base earnings for next year	$5,157,700
Average base earnings for next year	$322,400
Average pensionable earnings for next year	$373,200
Average years of Non-SME DB pensionable service	2.0 years
Average years of SME DB pensionable service	4.6 years
Average age	49.8 years

	31.12.2021
Active Defined Contribution Members without Defined Benefit Service	
Number	1,567
Total base earnings for next year	$157,658,300
Average base earnings for next year	$100,600
Average pensionable earnings next year	$107,700
Average age	38.7 years
Suspended Defined Contribution Members without Defined Benefit Service	
Number	46
Total base earnings for next year	$6,221,700
Average base earnings for next year	$135,300
Average age	46.5 years
Deferred Pensioners	
Number	1,109
Total annual pension	$8,361,800
Average annual pension	$7,500
Average age	48.4 years
Pensioners and Survivors	
Number	1,872
Total annual pension (including bridge benefits)	$44,185,500
Average annual pension (including bridge benefits)	$23,600
Total bridge benefits	$421,000
Average bridge benefits	$4,100
Average age	69.8 years

EI SPP Membership Data

As a supplemental plan, the EI SPP primarily provides certain benefits that would otherwise be payable under the EI RPP and EGD RPP, if not for limits imposed on registered pension plans by the *Income Tax Act* of Canada. Please refer to the EI RPP and EGD RPP active and suspended membership statistics for those members eligible for EI SPP benefits.

	31.12.2021
Deferred Pensioners	
Number pending receipt of deferred pension	44
Total annual supplemental pension	391,600
Average annual supplemental pension	$8,900
Average age	54.1 years
Pensioners and Survivors	
Number	213
Total annual supplemental pension	10,687,000
Average annual supplemental pension	$50,200
Average age	66.6 years

EGD RPP Membership Data

The membership summarized below is for the total plan.

	31.12.2021
Active and Disabled Members Accruing Defined Benefit Service (Non-SME)	
Number	397
Total base earnings for the following year	$31,447,200
Average base earnings for the following year	$79,200
Average years of pensionable service	12.7 years
Average age	45.4 years
Suspended Defined Benefit Members (Non-SME) Accruing Defined Contribution Service	
Number	5
Total base earnings for the following year	$402,500
Average base earnings for the following year	$80,500
Average years of pensionable service	9.7 years
Average age	52.5 years

	31.12.2021
Suspended Defined Benefit Members (Non-SME) Accruing Benefits in the EI Plan	
Number	1,243
Total base earnings for the following year	$124,753,000
Average base earnings for the following year	$100,400
Average years of pensionable service	8.9 years
Average age	45.8 years
Suspended Defined Benefit Members (SME) Accruing Benefits in the EI RPP	
Number	37
Total base earnings for the following year	$12,011,000
Average base earnings for the following year	$324,600
Average years of Non-SME pensionable service	10.0 years
Average years of SME pensionable service	2.7 years
Average age	52.6 years
Active Defined Contribution Members without Defined Benefit Service	
Number	11
Total base earnings for the following year	$894,200
Average base earnings for the following year	$81,300
Average age	46.8 years
Suspended Defined Contribution Members without Defined Benefit Service	
Number	71
Total base earnings for the following year	$6,953,800
Average base earnings for the following year	$97,900
Average age	46.3 years
Deferred Pensioners	
Number	347
Total annual lifetime pension	$2,180,900
Average annual pension	$6,300
Average age	48.5 years
Pensioners and Survivors	
Number	1,902
Total annual lifetime pension	$48,319,500
Average annual lifetime pension	$25,400
Total annual temporary pension	$1,273,200
Average annual temporary pension	$5,200
Average age	73.1 years

	31.12.2021
Pending Terminated Members	
Number	9

Pension Choices

The membership summarized below is for the total plan.

	01.01.2021
Active Members and Disabled members[6]	
DB Buy-up provisions:	
Number	53
Total base earnings for the following year	$6,358,900
Average base earnings for the following year	$120,000
Average years of pensionable service	7.3
Average age	42.1
DB Core provisions:	
Number	29
Total base earnings for the following year	$2,683,900
Average base earnings for the following year	$92,500
Average years of pensionable service	12.7
Average age	46.4
DB provisions (total):	
Number	82
Total base earnings for the following year	$9,042,800
Average base earnings for the following year	$110,300
Average years of pensionable service	8.5
Average age	43.2

[6] There are three foreign transfers as at January 1, 2022.

	01.01.2021
Suspended members DB	
Number	1,317
Total base earnings for the following year	$119,566,700
Average base earnings for the following year	$90,800
Average years of pensionable service	9.0
Average age	42.8
DC provisions	
Number	73
Total base earnings for the following year	$7,154,200
Average base earnings for the following year	$98,000
Average years of continuous service	22.6
Average age	53.1
Deferred Pensioners	
Number	199
Total annual pension	$1,693,200
Average annual pension	$8,500
Average age	47.5
Pensioners and Survivors	
Number	1,085
Total annual lifetime pension	$29,124,400
Total annual temporary pension	$2,421,200
Average annual lifetime pension	$26,800
Average age	69.7

M&S

The membership summarized below is for the total plan.

	01.01.2022
Suspended Members	
Number	14
Estimated total covered Payroll	$1,789,600
Estimated average annual covered pay	$127,800
Average years of pensionable service	29.0 years
Average age	58.6 years

	01.01.2022
Deferred Pensioners	
Number	4
Total annual pension	$58,700
Average annual pension	$14,700
Average age	63.1 years
Pensioners and Survivors	
Number	319
Total annual lifetime pension	$10,812,900
Total annual temporary pension	$162,600
Average annual lifetime pension	$33,900
Average age	77.3 years

BU Plan

The membership summarized below is for the total plan.

	01.01.2022
Suspended Members	
Number	16
Estimated total annual covered payroll	$1,427,000
Estimated average annual covered payroll	$89,200
Average years of pensionable service	29.4 years
Average age	58.6 years
Deferred Pensioners	
Number	4
Total annual pension	$18,500
Average annual pension	$4,600
Average age	59.4 years
Pensioners and Survivors	
Number	508
Total annual lifetime pension	$9,546,500
Total annual temporary pension	$240,300
Average annual lifetime pension	$18,800
Average age	76.9 years

Salaried Plan

The membership summarized below is for the total plan.

	01.01.2022
Suspended Members	
Number	7
Estimated total annual covered payroll	$697,800
Estimated average annual covered payroll	$99,700
Average years of pensionable service	32.3 years
Average age	61.2 years
Deferred Pensioners	
Number	47
Total annual lifetime pension	$132,800
Average annual lifetime pension	$2,800
Average age	63.3 years
Pensioners and Survivors	
Number	210
Total annual lifetime pension	$4,236,300
Total annual temporary pension	$128,900
Average annual lifetime pension	$20,200
Average age	77.8 years

Group 1

The membership summarized below is for the total plan.

	01.01.2022
Suspended Members	
Number	5
Estimated total annual covered payroll	$389,400
Estimated average annual covered payroll	$77,900
Average years of pensionable service	28.6 years
Average age	57.4 years
Deferred Pensioners	
Number	14
Total annual pension	$34,800
Average annual pension	$2,500
Average age	59.2 years

	01.01.2022
Pensioners and Survivors	
Number	52
Total annual lifetime pension	$482,300
Total annual temporary pension	$10,900
Average annual lifetime pension	$9,300
Average age	76.4 years

Group 3

The membership summarized below is for the total plan.

	01.01.2022
Suspended Members	
Number	4
Estimated total annual covered payroll[7]	$333,200
Estimated average annual covered payroll	$83,300
Average years of pensionable service	29.1 years
Average age	60.2 years
Deferred Pensioners	
Number	29
Total annual pension	$58,500
Average annual pension	$2,000
Average age	58.8 years
Pensioners and Survivors	
Number	42
Total annual lifetime pension	$441,500
Total annual temporary pension	$4,600
Average annual lifetime pension	$10,500
Average age	78.1 years

EGD SERP

The membership summarized below is for the total plan.

	31.12.2021
Pensioners and Survivors	
Number	26
Total annual lifetime pension	$1,097,300
Average annual lifetime pension	$42,200
Average age	76.6 years

EGD SSERP

The membership summarized below is for the total plan.

	31.12.2021
Pensioners and Survivors	
Number	4
Total annual lifetime pension	$425,000
Average annual lifetime pension	$106,200
Average age	82.6 years

LSE SERP

The membership summarized below is for the total plan.

	01.01.2022
Pensioners and survivors	
Number	178
Average annual lifetime pension	$52,700
Average age	70.0 years
Terminated vested members	
Number	9
Average annual lifetime pension	$15,600
Average age	57.4 years

Spectra OPEB Plan – Union Gas

Distribution of Members by Plan as at January 1, 2021				
	Harmonized Plan	**Common Plan**	**Other Grandfathered Plans**	**Total**
Union Active Members				
Number	750	0	0	750
Average age	43.9	n/a	n/a	43.9
Average service	12.3	n/a	n/a	12.3
Non-Union Active Members				
Number	851	0	0	851
Average age	44.4	n/a	n/a	44.4
Average service	14.0	n/a	n/a	14.0
Total				
Number	1,601	0	0	1,601
Average age	44.2	n/a	n/a	44.2
Average service	13.2	n/a	n/a	13.2
Retirees and Surviving Spouses				
Number	253	1072	551	1,876
Average age	61.2	67.3	81.6	70.7

EGD OPEB Plan – EGDI

Active Membership Data

	As at January 1, 2021			
	Number	**Average Age**	**Average Service**	**Average Salary**
Grandfathered Plan				
Non Union	0	N/A	N/A	N/A
Union	56	61.1	33.8	N/A
Part Time	1	73	19	N/A
Non-Grandfathered Plan (Harmonized Plan)	**2,010**	**43.7**	**11.9**	**N/A**
Total	**2067**	**44.2**	**12.5**	**N/A**

Inactive Membership Data

	As at January 1, 2021		
	Less than age 65	**Greater than age 65**	**Total**
Grandfathered Plan			
Number of Retirees	191	1,077	1,268
Average age of Retirees	62.3	76	73.9
Average Life Benefit	$158,995	$5,000	$28,196
Number of Spouses of Retirees	157	809	966
Average age of Spouses	62.2	73.3	71.5
Number of Surviving Spouses	30	237	267
Average age of Surviving Spouses	60.3	81.5	79.1
Non-Grandfathered Plan (Harmonized Plan)			
Number of Retirees			274
Average age of Retirees			63
Average Life Benefit			$10,000
Number of Spouses of Retirees			221
Average age of Spouses			62.5
Number of Surviving Spouses			7
Average age of Surviving Spouses			67.5

Appendix G

Summary of Plan Provisions

Mercer has used and relied on the plan documents, including amendments and interpretations of plan provisions, supplied by Enbridge Inc. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

The following plan summaries are not intended to be a complete description of the plans.

EI RPP – DB Provisions

The following is a summary of the main provisions of the DB component of the EI RPP that are applicable to employees of the Company.

Background	The EI RPP (the "Plan" throughout this table) became effective January 1, 1966. Members who are SMEs must participate in the DB component of the Plan. At July 1, 2001, all active and suspended members who were not SMEs were required to elect to participate in either the DB component or the DC component of the Plan for future service. All service prior to January 1, 1997 was credited as service in the DB component. Members previously had a choice between components effective January 1, 1997. Prior to January 1, 2018, members who were not SMEs could switch once more between the DB and DC components on the January 1 following the date they achieved 40 points or 60 points. Any such change affected service after the decision point only. Effective January 1, 2018, members in the DB component were required to remain in the DB component, while members in the DC component were required to transfer to the DB component (if they had five or more years of continuous service) or remain in the DC component (if they had less than five years of continuous service). Non-union employees who were accruing benefits in the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates ("EGD RPP") as at December 31, 2017 began accruing benefits in the Plan effective January 1, 2018. Non-union employees who were accruing benefits in the Legacy Spectra Plans as at December 31, 2018 began accruing benefits in the Plan effective January 1, 2019. Canadian employees who were members of the United Steelworkers union and who were accruing benefits in the Legacy Spectra Plans as at December 31, 2019 will begin accruing benefits in the Plan effective January 1, 2020. If these members were in the DB component of the EGD RPP or Legacy Spectra Plans, they transferred to the DB component of the Plan. If they were in the DC component of the EGD RPP or Pension Choices Plan, they transferred to the DB component of the Plan (if they had five or more years of continuous service) or the DC component of the Plan (if they had less than five years of continuous service). Non-SME employees who are newly hired by the Company into the Plan on or after January 1, 2018 will become members in the Plan and will participate in the DC component for five years of continuous service. Participants in the DC component will transfer to the DB component when they attain five years of continuous service.
Eligibility for Membership	New employees become members of the Plan immediately. On or after January 1, 2018, new employees who are not SMEs will participate in the DC component for five years of service and then transfer to the DB component. SMEs must participate in the DB component.
Vesting	All members of the DB component vest immediately upon enrolment.
Employee Contributions	Prior to January 1, 2018, no employee contributions were required or permitted. Effective January 1, 2018, non-SMEs are required to contribute 5.0% of base earnings.
Retirement Dates	<u>Normal Retirement Date:</u> The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. <u>Early Retirement Date:</u> A member may choose to retire as early as age 55.

Normal Retirement Pension	Non-SME Credited Service: *Prior to January 1, 2018:* 1.6% of Final Average Earnings multiplied by years of non-SME credited service; less 50% of the Canada Pension Plan entitlement. *On and after January 1, 2018:* 1.5% of Final Average Earnings multiplied by years of non-SME credited service. SME Credited Service: 2.0% of Final Average Earnings multiplied by years of SME credited service.
Final Average Earnings	Final Average Earnings is calculated using the highest 36 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, plus the sum of the highest three Pensionable Bonus payments made in the last five years divided by three. Pensionable Bonuses are as follows: a) For an SME: 50% of the actual bonus received applies for SME credited service after December 31, 1999. b) For any other member: 50% of the actual bonus received applies for non-SME credited service after June 30, 2001.
Canada Pension Plan Entitlement	Canada Pension Plan (CPP) entitlement refers to the CPP retirement benefit calculated at the member's retirement date. The benefit is calculated as if the member had reached age 65, multiplied by the ratio of the member's non-SME credited service after the later of January 1, 1966 or age 18 and prior to January 1, 2018, to the number of years of possible CPP coverage to age 65, recognizing the permitted dropout period of 15%, and reduced by 6% per year for every year the retirement date precedes age 65, to a maximum reduction of 30%.
Early Retirement Pension	The following benefits apply if a member retires early with the Company's consent: • If the member has attained age 60, the pension payable is as described above in the Normal Retirement section. • If the member has not attained age 60, the member is eligible for the benefits described in the previous paragraph, plus for non-SME credited service an additional benefit of a bridge pension payable to age 60 equal to 50% of the Canada Pension Plan entitlement. • If the member has not attained age 60 or 30 years of continuous service at retirement, an early retirement reduction of 5% per year is applicable from age 60. For SMEs at January 1, 2000, the early retirement reduction is 3% per year for all credited service. For employees who became SMEs after January 1, 2000, the 3% reduction only applies to SME credited service. The reduction applies to the benefit described in the immediately preceding paragraphs including the bridge pension. If a member retires without Company consent, the benefit is actuarially equivalent to the benefit payable at age 65.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of: • 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and • $3,245,56 or such other maximum as may apply from time to time, indexed to the date of pension commencement, multiplied by total credited service and reduced for early retirement in accordance with the ITA.

Indexation of Pensions in Payment	For pensions accrued prior to January 1, 2018: On December 1 of each year, a contractual cost of living increase equal to 50% of the annual increase in the Consumer Price Index will apply to pensions that have been in payment for at least one year. Prior to July 1, 2001, any increases to pensions in payment were on an ad-hoc basis. For pensions accrued on and after January 1, 2018: There is no indexation on pensions accrued on and after January 1, 2018.
Death Benefits	Death Before Eligible for Early Retirement: If a member dies before he is eligible for early retirement benefits, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to 100% of the commuted value of the member's reduced accrued pension deferred to age 55, in respect of all credited service. Death After Eligibility for Early Retirement: If a member dies after his early retirement date and before his pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive either a lump sum settlement or an immediate pension equal in value to 100% of the commuted value of the member's reduced accrued pension, in respect of all credited service. Death After Retirement: The death benefit payable is in accordance with the form elected. The normal form of pension is a Joint and 60% Survivor annuity for members with a spouse and a life annuity with a 15-year guarantee period for single members. Other optional forms are available on an actuarially equivalent basis. Members with a spouse must elect a Joint and Survivor pension with at least 60% continuing to the survivor.
Termination Benefits	If a member's employment terminates for reasons other than death or retirement, the member must make an election with respect to their accrued pension benefits. For pension benefits accrued prior to January 1, 2018: The member may elect either: • An indexed pension that is actuarially reduced from age 65; or • A non-indexed pension deferred to age 55 and reduced as if the member had retired with Company consent. For pension benefits accrued on and after January 1, 2018: The member may elect a non-indexed pension deferred to age 55 and reduced by 6% per year from age 65 (or actuarially reduced from age 65 if this results in a larger pension). In either case, the member has the option to transfer the value of the benefit to a locked-in RRSP.
Disability Benefits	A member whose disability commenced before July 1, 2001 is eligible to retire at age 60. A member whose disability commences after June 30, 2001 is eligible to retire at age 65. The disabled member's salary is assumed to increase with inflation to a maximum of 5% per year. The disabled member continues to accrue credited service while disabled.

EI RPP – DC Provisions

The following is a summary of the main provisions of the DC component of the EI RPP.

Background	The DC component of the Plan became effective January 1, 1997. Employer contributions are remitted to individual member accounts and are credited with interest. Members receive the balance of their individual employer account upon termination, death or retirement. At July 1, 2001 all active and suspended members who were not SMEs were required to elect to participate in either the DB component or the DC component of the Plan for future service. All service prior to January 1, 1997 was credited as service in the DB component. Members previously had a choice between components effective January 1, 1997. Prior to January 1, 2018, members who were not SMEs could switch once more between the DB and DC components on the January 1 following the date they achieved 40 points or 60 points. Any such change affected service after the decision point only. Effective January 1, 2018, members in the DB component were required to remain in the DB component, while members in the DC component were required to transfer to the DB component (if they had five or more years of continuous service) or remain in the DC component (if they had less than five years of continuous service). Non-union employees who were accruing benefits in the EGD RPP as at December 31, 2017 began accruing benefits in the Plan effective January 1, 2018. Non-union employees who were accruing benefits in the Legacy Spectra Plans as at December 31, 2018 began accruing benefits in the Plan effective January 1, 2019. Canadian employees who were members of the United Steelworkers union and who were accruing benefits in the Legacy Spectra Plans as at December 31, 2019 will begin accruing benefits in the Plan effective January 1, 2020. If these members were in the DB component of the EGD RPP or Legacy Spectra Plans, they transferred to the DB component of the Plan. If they were in the DC component of the EGD RPP or Pension Choices Plan, they transferred to the DB component of the Plan (if they had five or more years of continuous service) or the DC component of the Plan (if they had less than five years of continuous service). Non-SME employees who are newly hired by the Company into the Plan on or after January 1, 2018 will become members in the Plan and will participate in the DC component for five years of continuous service. Participants in the DC component will transfer to the DB component when they attain five years of continuous service.
Eligibility for Membership	New employees become members of the Plan immediately. On or after January 1, 2018, new employees will be in the DC component for five years of service and then move to the DB component. SMEs must participate in the DB component.
Vesting	All members of the DC component vest immediately.
Employee Contributions	No employee contributions are required or permitted.
Employer Contributions	Prior to January 1, 2018, employer contributions to the DC component were based on a member's points: • Less than 40 points: 5% of pensionable earnings • 40 to 60 points: 7% of pensionable earnings • greater than 60 points: 9% of pensionable earnings Effective January 1, 2018, employer contributions to the DC component are 5% of pensionable earnings.

Maximum Contribution	The employer contributions are limited by maximums under the ITA.
Pensionable Earnings	Base salary plus 50% of actual bonus received.

EI SPP

As a supplemental plan, the EI SPP primarily provides certain benefits that would otherwise be payable under the EI RPP and EGD RPP, if not for limits imposed on registered pension plans by the ITA. Please refer to SME and non-SME benefits under the EI RPP section of this Appendix. EI SPP benefits in relation to the EGD RPP for non-SMEs are not material to the results of the valuation.

EGD RPP – DB Provisions

The following is a summary of the main provisions of the DB component of the EGD RPP.

Background	The EGD RPP (the "Plan" throughout this table) became effective January 1, 1971. Benefits are based on a set formula and are entirely paid for by the Company. Effective July 1, 2001, the Plan was redesigned for all active or suspended members at that date. Prior to the redesign, participants in the DB component of the Plan accrued contributory credited service. Following the redesign, all active and suspended members were required to elect to participate in either the DB component or the DC component of the Plan for future service. Participants in the DB component of the Plan accrue non-contributory or SME credited service. Up to January 1, 2018, members who were not SMEs could switch between the DB and DC components on the January 1 following the date they achieved 40 points or 60 points. Any such change affected service after the decision point only. Members who were SMEs had to participate in the DB component of the Plan. Effective January 1, 2018, only new union employees can become members. All new or re-employed non-union members on or after January 1, 2018 must participate in The Retirement Plan for the Employees of Enbridge Inc. and Affiliates (the "EI RPP"). Also effective January 1, 2018, all non-union active members, except employees on salary continuance at that date, stopped accruing benefits in the Plan and start accruing pension benefits, in either the defined contribution (DC) or defined benefit (DB) provision of the EI RPP. For these non-union active employees, credited service earned under the Plan prior to January 1, 2018 will be frozen, but future pensionable earnings increases and future continuous service with the Company will be reflected in determining their ultimate pension benefits payable from this Plan, except for Pelican Affected Members where future pensionable earnings increases are not reflected. Effective January 1, 2022, no new members can join the plain. All union active members, except employees on salary continuance at that date, stopped accruing benefits in the Plan and start accruing pension benefits, in either the defined contribution (DC) or defined benefit (DB) provision of the EI RPP. For these union active employees, credited service earned under the Plan prior to January 1, 2022 will be frozen, but future pensionable earnings increases and future continuous service with the Company will be reflected in determining their ultimate pension benefits payable from this Plan.

Eligibility for Membership	New union employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. The Plan is closed to new non-union employees. The Plan will also be closed to new union employees effective January 1, 2022.
Vesting	All members are vested immediately upon entering the Plan.
Employee Contributions	No employee contributions are required or permitted based on the current plan provisions. Prior to July 1, 2001, employee contributions were required.
Retirement Dates	Normal Retirement Date: The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date: If a member has been in the Plan for at least two years, the member may choose to retire as early as age 55.
Normal Retirement Pension	Contributory Service: 2.0% of Final Five Year Average Earnings multiplied by years of contributory credited service; less 100% of the Contributory Canada Pension Plan Entitlement. Non-Contributory Service: 1.2% of Final Three Year Average Earnings multiplied by years of non-contributory credited service; less 50% of the Non-Contributory Canada Pension Plan Entitlement; SME Credited Service: 2.0% of Final Three Year Average Earnings multiplied by years of SME credited service.
Final Five Year Average Earnings	Highest 60 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, including 50% of the actual bonus received for senior executive employees, divided by five
Final Three Year Average Earnings	Highest 36 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, plus the sum of the highest three Pensionable Bonus payments made in the last five years, divided by three. For Non-Contributory and SME Credited Service, Pensionable Bonus is defined as 50% of the sum of eligible performance bonuses.
Canada Pension Plan Entitlement	Contributory Service: One thirty-fifth of 25% of the lesser of the average earnings in the 60 months immediately preceding the date of exit and average of the YMPE in the five calendar years, including the current year, preceding the date of exit, multiplied by contributory credited service, to a maximum of 35 years. Non-Contributory Service: Calculated as if the member had reached age 65, multiplied by the ratio of the member's non-contributory credited service after the later of January 1, 1966 or age 18, to the number of years of possible CPP coverage to age 65, recognizing the permitted dropout period of 15%, and reduced by 6% per year for every year the retirement date precedes age 65, to a maximum reduction of 30%.

Early Retirement Pension	The following benefits apply if a member retires early: • If the member has attained age 60, the pension payable is as described above in the Normal Retirement section. • If the member has 30 years of continuous Service or has attained age 60, the member is eligible for the benefits described in the previous paragraph plus, for contributory credited service, an additional benefit of a bridge pension payable to age 65 equal to 100% of the Contributory Canada Pension Plan Entitlement. • If the member has not attained age 60 the member is also eligible, for non-contributory credited service, for an additional benefit of a bridge pension payable to age 60 equal to 50% of the Non-Contributory Canada Pension Plan Entitlement. • If the member has not attained age 60 or 30 years of continuous service at retirement, an early retirement reduction of 5% per year is applicable from age 60 in respect of contributory and non-contributory credited service. For SMEs, the early retirement reduction is 3% per year for SME credited service. The reduction applies to the benefit described in the immediately preceding paragraphs including the bridge pensions.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of: • 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and • $3,245.56, or such other maximum as may apply from time to time indexed to the date of pension commencement, multiplied by his total credited Service and reduced for early retirement in accordance with the ITA rules.
Indexation of Pensions in Payment	On December 1 of each year a contractual cost of living increase equal to a percentage of the annual increase in the Consumer Price Index will apply to lifetime pensions in payment for at least one year. This percentage is 55% for contributory credited service and 50% for non-contributory and SME credited service. Indexation only applies to members that retire from active membership. Prior to July 1, 2001, any increases to pensions in payment were on an ad-hoc basis.
Death Benefits	<u>Death Before Eligible for Early Retirement</u> If a member dies before he is eligible for early retirement benefits, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to 100% of the commuted value of the member's reduced accrued pension deferred to age 55, in respect of all credited service. <u>Death After Eligibility for Early Retirement</u> If a member dies after his early retirement date and before his pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive either a lump sum settlement or an immediate pension equal in value to 100% of the commuted value of the member's reduced accrued pension, in respect of all credited service. <u>Death After Retirement</u> The death benefit payable is in accordance with the form elected. The normal form of pension is a Joint and 60% Survivor annuity for members with a spouse and a life annuity with a 15-year guarantee period for single members.
Termination Benefits	If a member's employment terminates for reasons other than death or retirement, the member is entitled to their reduced accrued pension deferred to age 55. The Member has the option to transfer the value of the benefit to a locked-in RRSP.

Disability Benefits	Disabled members are eligible to retire at age 65. For members whose disability commenced before July 1, 2001 salary is assumed to increase with the Average Industrial Wage, while for members whose disability commences after July 1, 2001 salary is assumed to increase with inflation, subject to a maximum of 5% per year, to retirement. The disabled member continues to accrue credited service while disabled.

EGD RPP – DC Provisions

The following is a summary of the main provisions of the DC component of the EGD RPP.

Background	The DC component of the EGD RPP (the "Plan" throughout this table) became effective July 1, 2001. Employer contributions are remitted to individual member accounts and are credited with interest. Members receive the balance of their individual employer account upon termination, death or retirement.
Eligibility for Membership	New union employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. The Plan is closed to new non-union employees.
Vesting	All members of the DC component vest immediately.
Employee Contributions	No employee contributions are required or permitted.
Employer Contributions	Employer contributions to the DC component are based on the member's points. • less than 40 points: 4.0% of pensionable earnings [7] • 40 to 60 points: 5.5% of pensionable earnings • greater than 60 points: 7.0% of pensionable earnings
Maximum Contribution	The employer contributions are limited to the amounts under the ITA.
Pensionable Earnings	Base salary plus 50% of actual bonus received.

Pension Choices Plan – DB Provisions

The following is a summary of the main provisions of the Pension Choices Plan.

Note that there are distinct provisions of the plan as follows:

— the Buy-up provisions;

— the Core provisions;

— the Grandfathered provisions; and

— the DC provisions.

[7] For members who were participating in the DC component of the Plan at June 30, 2001, the minimum employer contribution is 5.0% of pensionable DC earnings.

In addition, benefits accrued under certain other pension plans were preserved in the plan for members of those pensions plans who became members of the Plan. These other pension plans include:

- Union Gas Pension Plan for Salaried Employees Formerly Employed by Centra Gas Inc.;
- Union Gas Management and Supervisory Pension Plan;
- Union Gas Bargaining Unit Pension Plan;
- Union Gas Pension Plan – Group One;
- Union Gas Pension Plan – Group Three;
- Westcoast Energy Inc. Employees' Retirement Plan;
- ConocoPhillips Canada Limited Employees' Retirement Plan;
- Duke Energy Field Services Canada Ltd. Pension Plan;
- Pension Plan for Employees of Kinder Morgan Canada Inc.; and
- Legacy Pension Plan for Employees of Kinder Morgan Canada Inc.

For brevity, the provisions of the above pension plans are not described in the following summary.

Background	As noted above, the Pension Choices Plan (the "Plan" throughout this table) consists of DB provisions and DC provisions. The DB provisions include the Buy-up provisions, the Core provisions and the Grandfathered provisions. Each active DB member accrues benefits under only one of these provisions. The Plan, in its current form, became effective July 1, 1999. Prior to July 1, 1999, the Plan existed as the Union Gas Salaried Pension Plan and only the Grandfathered provisions were effective.
Eligibility for Membership	At July 1, 1999, members of the Plan were given a one-time opportunity to continue in the Grandfathered provisions, or to accrue future service in one of the newly established provisions (i.e., Buy-up provisions, Core provisions or DC provisions). Members who elected to accrue future service in the DC provisions were provided a lump sum initial account value equal to the value of benefits earned in the Plan prior to the date of joining the DC provisions. Effective January 1, 2019 all non-union employees ceased accruals in the Plan, and began accruing credited service under the harmonized provisions of the EI RPP. Through collective bargaining, the remaining unions with members have also agreed to join the harmonized provisions of the EI RPP, with various effective dates. All union employees who have agreed to join the EI RPP will have done so by January 1, 2022. The only employees that remain in the Plan are those Unifor union members have elected to do so. No new employees are permitted to join the Plan after December 31, 2021. In addition, at various dates in the past on and after July 1, 1999 (depending on the other pension plan in question), members of certain other pension plans became members of the Plan and there were transfers of assets and liabilities from the other pension plans to the Plan in respect of these members' benefits accrued under the other pension plans.
<u>Buy up Provisions</u>	
Employee Contributions	Members are required to contribute 5.0% of pensionable earnings. These contributions are waived for executives.

Retirement Dates	Normal Retirement Date: The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date: If a member has been in the Plan for at least two years, the member may choose to retire as early as age 55.
Normal Retirement Pension	2.0% of the annualized average of a member's highest 36 consecutive months of pensionable earnings; MULTIPLIED BY The member's total years of pensionable service in the Buy-up provisions.
Pensionable Earnings	Base pay, including any applicable Northern Allowance, including STIP payments, but exclusive of overtime and other exceptional forms of compensation.
Northern Allowance	Additional compensation paid to members as a result of working in a remote location.
Early Retirement Pension	The following benefits apply if a member retires early: • If the member has attained age 62 or if age plus continuous service totals at least 85 years, the pension payable is as described above in the Normal Retirement Pension section. • Otherwise, an early retirement reduction of 0.25% per month is applicable from age 62. The reduction applies to the benefit described in the Normal Retirement Pension section.
Postponed Retirement Pension	The pension payable is as described above in the Normal Retirement Pension section, but reflecting service to the Postponed Retirement Date. The pension may commence on the first day of any month after Normal Retirement Date, but not later than December 1st of the calendar year the member attains age 71.
Maximum Pension	The total annual pension payable upon retirement, death or termination of employment cannot exceed the lesser of: • 2% of the average of the best three consecutive years of total compensation paid to the member by the Company; and • $3,092.22 or such other maximum as may apply from time to time; MULTIPLIED BY The member's total years of pensionable service in the Buy-up provisions; and REDUCED FOR Early retirement in accordance with the Income Tax Act rules.
Death Benefits	Pre-retirement: If a member dies before any pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive a value equal to 100% of the commuted value of the member's accrued pension, and a refund of contributions with interest which are in excess of 50% of the value of benefits accrued. Post-retirement: The death benefit payable is in accordance with the form elected. The normal form of pension is a life annuity with a 10-year guarantee period. Other optional forms are available on an actuarially equivalent basis.
Termination Benefits	A deferred lifetime pension, based on the member's pensionable earnings, contributions and pensionable service in the Buy-up provisions up to the date of termination. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an early retirement pension as early as age 55. The pension is reduced by 0.5% per month that the pension commencement date precedes age 65 (provided such reduction is not greater than actuarial equivalence). In addition, the member receives a refund of required contributions with interest which are in excess of 50% of the value of benefits accrued.

Disability Benefits	Upon total and permanent disability prior to Normal Retirement Date, a member's service continues to accrue until the earlier of the return to employment and age 65. Members must elect to either: i. continue making required member contributions, in which case they will continue to accrue benefits under the Buy-up provisions while disabled; or ii. cease making required member contributions, in which case they will accrue benefits under the Core provisions while disabled. A member who elects to accrue benefits under the Core provisions during a period of disability and who subsequently ceases to be disabled and returns to active employment shall make a one-time election to accrue future benefits under the Buy-up provisions or the Core provisions.
Pension Credit	Members may receive pension credits, which are expressed as a percentage of pensionable earnings and can be used by members to decrease their required contributions to the plan. The pension credit is one of the following: i. 1.75% of pensionable earnings; ii. 0.5% of pensionable earnings; or iii. 0.0% of pensionable earnings. The pension credit will vary by member based on hire date, union affiliation and employer.
Ancillary Benefits	Members may purchase additional benefits with accumulated amounts in their individual ancillary accounts. Contributions are remitted to the ancillary accounts on a voluntary basis up to the lesser of: i. 9% of earnings less member required contributions; and ii. 70% of the Pension Adjustment, plus $600, less member required contributions. Members direct investment of their ancillary accounts, choosing from among a number of available investment options. Upon retirement, members must apply the accumulated amounts in their ancillary accounts to purchase ancillary benefits. Available ancillary benefits include additional survivor benefits, additional bridging benefits, additional lifetime benefits and indexing.
<u>Core Provisions</u>	
Employee Contributions	No employee contributions are required.
Retirement Dates	<u>Normal Retirement Date:</u> The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. <u>Early Retirement Date:</u> The early retirement date is the first day of the month coincident with or next following the member's 55th birthday.
Normal Retirement Pension	1.0% of the annualized average of a member's highest 36 consecutive months of pensionable earnings; MULTIPLIED BY The member's total years of pensionable service in the Core provisions.
Pensionable Earnings	Base pay, including any applicable Northern Allowance, including STIP payments, but exclusive of overtime and other exceptional forms of compensation.
Northern Allowance	Additional compensation paid to members as a result of working in a remote location.
Early Retirement Pension	The following benefits apply if a member retires early: • If the member has attained age 62 or if age plus continuous service totals at least 85 years, the pension payable is as described above in the Normal Retirement Pension section. • Otherwise, an early retirement reduction of 0.25% per month is applicable from age 62. The reduction applies to the benefit described in the Normal Retirement Pension section.

<table>
<tr><td>Postponed Retirement Pension</td><td>The pension payable is as described above in the Normal Retirement Pension section, but reflecting service to the Postponed Retirement Date. The pension may commence on the first day of any month after Normal Retirement Date, but not later than December 1st of the calendar year the member attains age 71.</td></tr>
<tr><td>Maximum Pension</td><td>The total annual pension payable upon retirement, death or termination of employment cannot exceed the lesser of:
• 2% of the average of the best three consecutive years of total compensation paid to the member by the Company; and
• $3,092.22 or such other maximum as may apply from time to time;
MULTIPLIED BY
The member’s total years of pensionable service in the Core provisions; and
REDUCED FOR
Early retirement in accordance with the Income Tax Act rules.</td></tr>
<tr><td>Death Benefits</td><td><u>Pre-retirement:</u>
If a member dies before any pension payments have begun, the member’s spouse, or beneficiary if there is no spouse, will receive a value equal to 100% of the commuted value of the member’s accrued pension.
<u>Post-retirement:</u>
The death benefit payable is in accordance with the form elected. The normal form of pension is a life annuity with a 10-year guarantee period. Other optional forms are available on an actuarially equivalent basis.</td></tr>
<tr><td>Termination Benefits</td><td>A deferred lifetime pension, based on the member’s pensionable earnings, contributions and pensionable service in the Core provisions up to the date of termination. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an early retirement pension as early as age 55. The pension is reduced by 0.5% per month that the pension commencement date precedes age 65 (provided such reduction is not greater than actuarial equivalence).
In addition, the member receives a refund of contributions (if applicable) with interest which are in excess of 50% of the value of benefits accrued.</td></tr>
<tr><td>Disability Benefits</td><td>Upon total and permanent disability prior to Normal Retirement Date, a member’s service continues to accrue until the earlier of the return to employment and age 65.</td></tr>
<tr><td>Pension Credit</td><td>A member may receive a pension credit, which is expressed as a percentage of pensionable earnings.
The pension credit is one of the following:
i. 1.75% of pensionable earnings;
ii. 0.5% of pensionable earnings; or
iii. 0.0% of pensionable earnings.
The pension credit will vary by member based on hire date, union affiliation and employer.</td></tr>
<tr><td>Ancillary Benefits</td><td>Members may purchase additional benefits with accumulated amounts in their individual ancillary accounts. Contributions are remitted to the ancillary accounts on a voluntary basis up to the lesser of:
i. 9% of earnings less member required contributions; and
ii. 70% of the Pension Adjustment, plus $600, less member required contributions.
Members direct investment of their ancillary accounts, choosing from among a number of available investment options. Upon retirement, members must apply the accumulated amounts in their ancillary accounts to purchase ancillary benefits. Available ancillary benefits include additional survivor benefits, additional bridging benefits, additional lifetime benefits and indexing.</td></tr>
</table>

Grandfathered Provisions	
Employee Contributions	3.5% of pensionable earnings up to the YMPE, plus 5.0% of pensionable earnings in excess of the YMPE.
Retirement Dates	Normal Retirement Date: The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date: A member may choose to retire as early as age 55 or upon completion of 30 years of pensionable service.
Normal Retirement Pension	1.30% of the annualized average of a member's highest 36 consecutive months of pensionable earnings, up to the annualized average of the YMPE during the same 36 consecutive months; PLUS 1.65% of the excess, if any, of the annualized average of a member's highest 36 consecutive months of pensionable earnings, over the annualized average of the YMPE during the same 36 consecutive months; MULTIPLIED BY The member's total years of pensionable service in the Grandfathered provisions.
Pensionable Earnings	Base pay, including STIP payments, but exclusive of overtime and other exceptional forms of compensation.
Early Retirement Pension	The pension payable is as described in the Normal Retirement Pension section, but reduced by: i. 0.25% for each month by which the Early Retirement Date precedes attainment of age 62; plus ii. 0.25% for each complete month by which the Early Retirement Date precedes attainment of age 60. No reduction applies if age plus pensionable service totals at least 90 years. In addition, a temporary pension equal to 1/35 of $400 for each year of pensionable service in the Grandfathered provisions, up to a maximum of 35 years, is payable from Early Retirement Date to Normal Retirement Date.
Postponed Retirement Pension	The pension payable is as described above in the Normal Retirement Pension section, but reflecting service to the Postponed Retirement Date. The pension may commence on the first day of any month after Normal Retirement Date, but not later than December 1st of the calendar year the member attains age 71.
Maximum Pension	The total annual pension payable upon retirement, death or termination of employment cannot exceed the lesser of: • 2% of the average of the best three consecutive years of total compensation paid to the member by the Company; and • $3,092.22 or such other maximum as may apply from time to time; MULTIPLIED BY The member's total years of pensionable service in the Grandfathered provisions; and REDUCED FOR Early retirement in accordance with the *Income Tax Act* rules.

Death Benefits	Pre-retirement: • For service prior to January 1, 1987: refund of contributions with interest • For service on or after January 1, 1987: the sum of the actuarial equivalent of the member's pension accrued to date of death, and the refund of contributions with interest which are in excess of 50% of the value of benefits accrued in respect of such service. Post-retirement: The death benefit payable is in accordance with the form elected. The normal form of payment provides for a refund of contributions with interest to retirement date in excess of the aggregate pension payments received by the member. Members may choose from a number of available optional forms of payment, on an actuarially equivalent basis.
Termination Benefits	A deferred lifetime pension, based on the member's pensionable earnings, contributions and pensionable service in the Grandfathered provisions up to the date of termination. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an early retirement pension commencing as early as age 55. The pension is reduced on an actuarial equivalent basis from age 65. The minimum monthly pension in respect of pensionable service in the Grandfathered provisions prior to January 1, 1987 is a monthly pension which is the actuarial equivalent of the member's required contributions with interest during those pensionable service years. In addition, in respect of pensionable service in the Grandfathered provisions after January 1, 1987, the member receives a refund of contributions with interest for those pensionable service years which are in excess of 50% of the value of benefits accrued during those pensionable service years.
Disability Benefits	Upon total and permanent disability prior to Normal Retirement Date, required contributions cease and service continues to accrue until the earlier of the return to employment and age 65.

Pension Choices Plan – DC Provisions

Background	The DC provisions became effective July 1, 1999. Employer and employee contributions are remitted to individual member accounts and are credited with interest. Members direct the investment of their individual member accounts, choosing from a number of available investment options. Members receive the balance of their individual employer and employee account upon termination, death or retirement.
Employee Contributions	No employee contributions are required.
Employer Contributions	The Company contributes a percentage of pensionable earnings to each member's account based on the age and continuous service of the member on January 1 of the applicable year, as follows:

Age plus Continuous Service	Percentage
Less than 40 years	3.50%
Greater than 40 years and less than 50 years	4.50%
Greater than 50 years and less than 60 years	5.50%
Greater than 60 years and less than 70 years	6.50%
Greater than 70 years and less than 80 years	7.50%
Greater than 80 years and less than 90 years	8.50%
Greater or equal to 90 years	9.50%

Maximum Contribution	The employer contributions are limited to the amounts under the Income Tax Act.
Pensionable Earnings	Base salary including any applicable Northern Allowance, including STIP payments, but exclusive of overtime and other exceptional forms of compensation.
Northern Allowance	Additional compensation paid to members as a result of working in a remote location.
Disability Benefits	The Company continues to remit contributions to the account of a member who is totally and permanently disabled until such time as the member ceases to be disabled or the member attains age 65.

Union Gas Management and Supervisory Pension Plan

Background	The Plan became effective January 1, 1974. The Plan was closed to new entrants effective January 1, 1999. Effective January 1, 2019, all members stopped accruing benefits in the Plan and began accruing pension benefits in the Retirement Plan for Employees of Enbridge Inc. and Affiliates (the "EI RPP")sponsored by the Company.
Employee Contributions	Active members were required to contribute, in each year, 5% of earnings in excess of the YMPE.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date • The member may choose to retire as early as age 55 or at completion of 30 years of Credited Service. For the purpose of determining early retirement eligibility, service accrued after January 1, 2019 in the EI RPP shall be included in the calculation of Credited Service.
Normal Retirement Pension	**For Service Before January 1, 1975** 1.75% of the member's Best Average Earnings MULTIPLIED BY The member's total years of Credited Service before January 1, 1975 **For Supervisory Service On or After January 1, 1975** 1.30% of the member's Best Average Earnings up to the Best Average YMPE PLUS 1.75% of the excess, if any, of the member's Best Average Earnings over the Best Average YMPE MULTIPLIED BY The member's total years of Credited Supervisory Service on or after January 1, 1975 **For Non-Supervisory Service On or After January 1, 1975** 1.30% of the member's Best Average Earnings up to the Best Average YMPE PLUS 1.65% of the excess, if any, of the member's Best Average Earnings over the Best Average YMPE MULTIPLIED BY The member's total years of Credited Non-Supervisory Service on or after January 1, 1975
Best Average Earnings	Annualized average pensionable earnings for the 36 consecutive months for which they are the highest

Best Average YMPE	Annualized average of the YMPE during the same period as the Best Average Earnings
Pensionable Earnings	Base pay, plus applicable STIP bonuses, but exclusive of overtime and other exceptional forms of compensation.
Early Retirement Pension	If a member retires early, the member will be entitled to a pension that is calculated the same way as for a normal retirement. The basic pension payable, however, will be reduced by a given percentage, as follows: • For each month preceding age 60: 0.25% per month, plus • For each month preceding age 62: 0.25% per month • No reduction applies if the sum of age and Credited Service is at least 90 years. For the purpose of determining unreduced early retirement eligibility, service accrued after January 1, 2019 in the EI RPP shall be included in the calculation of Credited Service.
Supplemental Pension Entitlement	If a member retires early from active status, shall receive a monthly supplemental pension equal to 1/35 of $400, multiplied by the lesser of 35 year and Credited Service as at the date of retirement. Supplemental pension payments will cease on the earlier of the first day of the month in which the member dies, or attains age 65.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of: • 2% of the average of the best three consecutive years of total compensation paid to the member by the Company, multiplied by total Credited Service; and • $3,245.56 or such other maximum permitted under the *Income Tax Act*, multiplied by the member's total credited service. The maximum pension is determined at the date of pension commencement and reduced for early retirement in accordance with the *Income Tax Act* rules.
Death Benefits	Pre-retirement: • If a member dies before the normal retirement date and before any pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive a refund of contributions with interest for Credited Service prior to January 1, 1987, plus a lump sum settlement equal to the value of the benefits to which the member would have been entitled had employment terminated on the date of death for Credited Service on or after January 1, 1987. Post retirement: • The normal form of payment for a member with no spouse is a lifetime pension guaranteed for a period such that the aggregate pension payments are at least equal to the member's contributions with interest at retirement. The normal form of payment for a member with a spouse is a joint and 60% survivor annuity. However, the member may elect to receive an optional form of pension on an actuarial equivalent basis.
Termination Benefits	A deferred lifetime pension, based on the member's earnings, contributions and credited service up to the date of termination. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an actuarially reduced early retirement pension as early as age 55.
Excess Member Contributions	For Credited Service before January 1, 1987: • Refund of contributions with interest which are in excess of 100% of the value of benefits accrued in respect of such Credited Service. For Credited Service on and after January 1, 1987: • Refund of contributions with interest which are in excess of 50% of the value of benefits accrued in respect of such Credited Service.

Union Gas Bargaining Unit Pension Plan

Background	The Plan provides benefits based on a final average earnings formula.
Eligibility for Membership	The plan was closed to employees hired on or after January 1, 2001. Effective January 1, 2021, members will cease to accrue credited service in the Plan, and begin accruing benefits in harmonized provisions of the Retirement Plan for Employees of Enbridge Inc. and Affiliates.
Employee Contributions	3.5% of earnings up to the YMPE, plus 5.0%, if any, in excess of the YMPE.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date • The early retirement date is the first day of the month coincident with or next following the member's 55th birthday or completion of 30 years of credited service.
Normal Retirement Pension	1.3% of the annualized average pensionable earnings for the 36 consecutive months for which they are the highest, up to the annualized average of the YMPE during the same period PLUS 1.65% of the excess, if any, of the member's annualized average pensionable earnings for the 36 consecutive months for which they are the highest, over the annualized average of the YMPE during the same period MULTIPLIED BY The member's total years of credited service.
Pensionable Earnings	Base pay, plus applicable STIP bonuses.
Early Retirement Pension	If a member retires early, the member will be entitled to a pension that is calculated the same way as for a normal retirement. The basic pension payable, however, will be reduced by a given percentage for each month before the normal retirement date, as follows: • For each month preceding the age 62: 0.25% per month, plus • For each month preceding the age 60: 0.50% per month In addition, the member will be entitled to a temporary monthly pension, payable to normal retirement age, equal to: • 1/35 of $400 for each year of credited service (max. 35 years)
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed: • $3,245.56 or such other maximum permitted under the Income Tax Act, multiplied by the member's total credited service. The maximum pension is determined at the date of pension commencement and reduced for an early retirement in accordance with the *Income Tax Act* rules.

Death Benefits	Pre-retirement: • If a member dies before the normal retirement date and before any pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive a refund of the member's contributions made before January 1, 1987 with interest, plus, a lump sum settlement equal to the value of the benefits accrued since January1, 1987 to which the member would have been entitled had employment terminated on the date of death. Post retirement: • The normal form of payment is a lifetime pension guaranteed for a period such that the aggregate pension payments are at least equal to the member's contributions with interest at retirement. However, the member may elect to receive an optional form of pension on an actuarial equivalent basis.
Termination Benefits	A deferred lifetime pension, based on the member's earnings, contributions and credited service up to the date of termination. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an actuarially reduced early retirement pension as early as age 55.

Union Gas Pension Plan for Salaried Employees Formerly Employed by Centra Gas Inc.

Background	The Plan was amended and restated effective January 1, 2019. Benefits are based on a set formula and are entirely paid for by the Company. Effective January 1, 2019, all members, except employees on salary continuance at that date, stopped accruing benefits in the Plan and started accruing pension benefits in another pension plan sponsored by the company.
Eligibility for Membership	The plan was closed to new entrants effective January 1, 1999.
Employee Contributions	No employee contributions are required.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date • Age 55.
Normal Retirement Pension	**For Service Before January 1, 1986** i) 1.15% of the annualized average pensionable earnings for the 60 consecutive months for which they are the highest, up to the annualized average of the YMPE during the same 60 months of membership PLUS 1.75% of the excess, if any, of the member's annualized average pensionable earnings for the 60 consecutive months for which they are the highest, over the annualized average of the YMPE during the same 60 months of membership MULTIPLIED BY The member's total years of contributory credited service before January 1, 1986. ii) 0.6% of the annualized average pensionable earnings for the 60 consecutive months for which they are the highest, up to the annualized average of the YMPE during the same 60 months of membership PLUS 1.2% of the excess, if any, of the member's annualized average pensionable earnings for the 60 consecutive months for which they are the highest, over the annualized average of the YMPE during the same 60 months of membership MULTIPLIED BY The member's total years of non-contributory credited service before January 1, 1986. **For Service On or After January 1, 1986** 1.0% of the annualized average pensionable earnings for the 60 consecutive months for which they are the highest, up to the annualized average of the YMPE during the same 60 months of membership PLUS 1.5% of the excess, if any, of the member's annualized average pensionable earnings for the 60 consecutive months for which they are the highest, over the annualized average of the YMPE during the same 60 months of membership MULTIPLIED BY The member's total years of credited service on or after January 1, 1986.

Pensionable Earnings	Base pay, plus applicable STIP bonuses, but exclusive of overtime and other exceptional forms of compensation.
Early Retirement Pension	If a member retires early, the member will be entitled to a pension that is calculated the same way as for a normal retirement. The basic pension payable, however, will be reduced by a given percentage for each month before the normal retirement date, as follows: • For each month preceding age 62: 0.25% per month • No reduction applies if the sum of age and continuous service is at least 90 years.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed: • 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and • $3,245.56 or such other maximum permitted under the Income Tax Act, multiplied by the member's total credited service. The maximum pension is determined at the date of pension commencement and reduced for early retirement in accordance with the *Income Tax Act* rules.
Death Benefits	Pre-retirement: • If a member dies before the normal retirement date and before any pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to the value of the benefits to which the member would have been entitled had employment terminated on the date of death. Post retirement: • The normal form of payment is a lifetime pension guaranteed for a period of 10 years if the member has no spouse. If the member has a spouse, the normal form of payment is a lifetime pension continuing at 50% of the original amount to the surviving spouse for their lifetime. No less than 60 monthly payments of the original amount shall be made to the member and the spouse combined. However, the member may elect to receive an optional form of pension on an actuarial equivalent basis.
Termination Benefits	A deferred lifetime pension, based on the member's earnings, contributions and credited service up to the date of termination. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an actuarially reduced early retirement pension as early as age 55.
Additional Benefits	Refund of contributions with interest in respect of Credited Service accrued before January 1, 1986 which are in excess of 100% of the value of benefits accrued in respect of such Credited Service.

Union Gas Pension Plan – Group One

Background	The plan consists of two parts. A final average earnings provision effective for all service, with a provision that the benefit for service up to June 30, 2004 is not less than a benefit rate multiplied by the credited service for that period.
Eligibility for Membership	Members of the United Steelworkers Local 2021 and 7846. Employees hired prior to January 1, 2004 were permitted to join the plan after completion of their probationary period. The plan was closed to new entrants effective January 1, 2004. Effective January 1, 2020, members began accruing benefits in harmonized provisions of the Retirement Plan for Employees of Enbridge Inc. and Affiliates.
Employee Contributions	**For Service Before July 1, 2004** No employee contributions are required. **For Service On or After July 1, 2004** Members are required to contribute 3.5% of earnings up to the YMPE, plus 5.0%, if any, in excess of the YMPE.
Retirement Dates	**Normal Retirement Date** The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. **Early Retirement Date** • Age 55 for service before July 1, 2004. • Age 55 or at completion of 30 years of credited service for service on or after July 1, 2004.
Normal Retirement Pension	**For Service Before July 1, 2004** THE GREATER OF A monthly dollar amount of $49.50, times 12 AND 1.30% of the annualized average pensionable earnings for the 36 consecutive months for which they are the highest, up to the annualized average of the YMPE during the same period PLUS 1.65% of the excess, if any, of the member's annualized average pensionable earnings for the 36 consecutive months for which they are the highest, over the annualized average of the YMPE during the same period MULTIPLIED BY The member's total years of credited service before July 1, 2004. **For Service On or After July 1, 2004** 1.30% of the annualized average pensionable earnings for the 36 consecutive months for which they are the highest, up to the annualized average of the YMPE during the same period PLUS 1.65% of the excess, if any, of the member's annualized average pensionable earnings for the 36 consecutive months for which they are the highest, over the annualized average of the YMPE during the same period MULTIPLIED BY The member's total years of credited service on or after July 1, 2004.
Temporary Pension	1/35 of $4,800 for each year of Credited Service (maximum 35 years) payable from early retirement date to normal retirement date.

Pensionable Earnings	Base pay, plus applicable STIP bonuses, but excludes overtime and other exceptional forms of compensation.
Early Retirement Pension	If a member retires early, the member will be entitled to a pension that is calculated the same way as for normal retirement. The basic pension payable, however, will be reduced by a given percentage for each month before the normal retirement date, as follows: **For Service Before July 1, 2004** For each month preceding age 62: 0.25% per month **For Service On or After July 1, 2004** • For each month preceding age 62: 0.25% per month, plus • For each month preceding age 60: 0.25% per month No reduction applies if the sum of age and continuous service is at least 90 years.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed: • 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and • $3,245.56 or such other maximum permitted under the Income Tax Act, multiplied by the member's total credited service. The maximum pension is determined at the date of pension commencement and reduced for early retirement in accordance with the *Income Tax Act* rules.
Death Benefits	Pre-retirement: • If a member dies before the normal retirement date and before any pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to the value of the benefits to which the member would have been entitled had employment terminated on the date of death. Post retirement: • The normal form of payment is a lifetime pension guaranteed for a period such that the aggregate pension payments are at least equal to the member's contributions with interest at retirement. However, the member may elect to receive an optional form of pension on an actuarial equivalent basis (for members with a spouse, the normal form of pension under the unit benefit provision is J&S 60%).
Termination Benefits	A deferred lifetime pension based on the member's earnings, contributions and credited service up to the date of termination. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an actuarially reduced early retirement pension as early as age 55. The pension is reduced by 0.25% per month that the pension commencement date precedes the earlier of age 60, the date the member would have completed 30 years of service, or the date the aggregate of the member's age and service would equal 80 (provided such reduction is not greater than actuarial equivalence).
Additional Benefits	Refund of contributions with interest in respect of Credited Service accrued on or after July 1, 2004 which are in excess of 50% of the value of benefits accrued in respect of such Credited Service.

Union Gas Pension Plan – Group Three

Background	The plan consists of two parts. A final average earnings provision effective for all service, with a provision that the benefit for service up to June 30, 2004 is not less than a benefit rate multiplied by the credited service for that period.
Eligibility for Membership	Members of the Communication, Energy and Paperworkers' Union Local's 790, 795 and 37. Employees hired prior to January 1, 2004 were permitted to join the plan after completion of their probationary period. The plan was closed to new entrants effective January 1, 2004. Effective January 1, 2021, members will begin accruing benefits in the EI Plan.
Employee Contributions	**For Service Before July 1, 2004** No employee contributions are required. **For Service On or After July 1, 2004** Members are required to contribute 3.5% of earnings up to the YMPE, plus 5.0%, if any, in excess of the YMPE.
Retirement Dates	**Normal Retirement Date** The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. **Early Retirement Date** • Age 55 for service before July 1, 2004. • Age 55 or at completion of 30 years of credited service for service on or after July 1, 2004.
Normal Retirement Pension	**For Service Before July 1, 2004** THE GREATER OF A monthly dollar amount of $45.25, times 12 AND 1.30% of the annualized average pensionable earnings for the 36 consecutive months for which they are the highest, up to the annualized average of the YMPE during the same period PLUS 1.65% of the excess, if any, of the member's annualized average pensionable earnings for the 36 consecutive months for which they are the highest, over the annualized average of the YMPE during the same period MULTIPLIED BY The member's total years of credited service before July 1, 2004. **For Service On or After July 1, 2004** 1.30% of the annualized average pensionable earnings for the 36 consecutive months for which they are the highest, up to the annualized average of the YMPE during the same period PLUS 1.65% of the excess, if any, of the member's annualized average pensionable earnings for the 36 consecutive months for which they are the highest, over the annualized average of the YMPE during the same period MULTIPLIED BY The member's total years of credited service on or after July 1, 2004.
Temporary Pension	1/35 of $4,800 for each year of Credited Service (maximum 35 years) payable from early retirement date to normal retirement date.
Pensionable Earnings	Base pay, plus applicable STIP bonuses, but excludes overtime and other exceptional forms of compensation.

Early Retirement Pension	If a member retires early, the member will be entitled to a pension that is calculated the same way as for a normal retirement. The basic pension payable, however, will be reduced by a given percentage for each month before the normal retirement date, as follows: **For Service Before July 1, 2004** For each month preceding age 62: 0.25% per month **For Service On or After July 1, 2004** • For each month preceding age 62: 0.25% per month, plus • For each month preceding age 60: 0.25% per month • No reduction applies if the sum of age and continuous service is at least 90 years.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed: • 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and • $3,245.56 or such other maximum permitted under the Income Tax Act, multiplied by the member's total credited service. The maximum pension is determined at the date of pension commencement and reduced for an early retirement in accordance with the *Income Tax Act* rules.
Death Benefits	Pre-retirement: • If a member dies before the normal retirement date and before any pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to the value of the benefits to which the member would have been entitled had employment terminated on the date of death. Post retirement: • The normal form of payment is a lifetime pension guaranteed for a period such that the aggregate pension payments are at least equal to the member's contributions with interest at retirement. However, the member may elect to receive an optional form of pension on an actuarial equivalent basis (for married members, the normal form of pension under the unit benefit provision is J&S 60%).
Termination Benefits	A deferred lifetime pension based on the member's earnings, contributions and credited service up to the date of termination. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an actuarially reduced early retirement pension as early as age 55. The pension is reduced by 0.25% per month that the pension commencement date precedes the earlier of age 60, the date the member would have completed 30 years of service, or the date the aggregate of the member's age and service would equal 80 (provided such reduction is not greater than actuarial equivalence).
Additional Benefits	Refund of contributions with interest in respect of Credited Service accrued on or after July 1, 2004 which are in excess of 50% of the value of benefits accrued in respect of such Credited Service.

Spectra Energy Supplemental Executive Retirement Plan and Spectra Energy Maximum Pension Limits Plan

The LSE SERP provides pension benefits to members of Legacy Spectra Plans whose benefits payable from their respective plan on retirement exceeds the maximum pension limits imposed under the *Income Tax Act.*

Supplemental Executive Retirement Plan of Enbridge Gas Distribution and Affiliates

Background	The EGD RPP became effective January 1, 1971. The EGD SERP became effective November 19, 1987. It provides, to designated employees, benefit amounts that would otherwise be payable under the EGD RPP beyond the ITA maximum pension limit on service accrued prior to January 1, 2000. Benefits are based on a set formula and are entirely paid for by the Company.
Eligibility for Membership	The EGD SERP is closed to new entrants, and the only remaining members are pensioners and survivors.
Death Benefits	The normal form of payment is a lifetime pension guaranteed for 15 years for single members, or a joint and survivor pension with 60% payable for a member's surviving spouse's lifetime for married members. However, the member may elect to receive an optional form of pension on an actuarial equivalent basis.
Post-Retirement Increases	Subsequent to retirement, member benefits are granted an annual increase equal to 55% of the Consumer Price Index, up to a maximum annual increase of 5%. Increases are granted on December 1 of each year, beginning after the first anniversary of retirement from active status.

Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc.

Background	The EGD SSERP became effective November 19, 1984. It provides, to designated employees, benefit amounts that would otherwise be payable under the EGD RPP beyond the ITA maximum pension limit on specific service.
Eligibility for Membership	Only members designated by Enbridge Gas Distribution Inc. were able to join the Plan. The EGD SSERP is closed to new entrants, and the only remaining members are pensioners and survivors.
Post-Retirement Increases	Subsequent to retirement, member benefits are granted an annual increase equal to 55% of the Consumer Price Index, subject to a maximum annual increase of 5%.

Harmonized OPEB Plan (Applies to both EGD and Spectra OPEB plans)

In 2017, Enbridge approved changes to plan provisions that will affect benefits for non-union employees retiring on and after January 1, 2020. In addition, as a result of changes implemented in 2019, all union employees residing outside of B.C. are also eligible for the new harmonized plan for retirements on or after January 1, 2020. Effective January 1, 2021, all remaining Union employees are eligible for the new harmonized plan. The plan is identical to the EI and EGD non grandfathered plans shown below except that no portion of MSP premiums (The BC government have since eliminated MSP premiums) are payable by the Company.

Plan Summary

Eligibility

Employees will be eligible for the plan if the employee has at least five years of employment when they retire.

On the retiree's death, the health spending account continues for dependents.

Cost Sharing

All costs for retiree benefits are employer paid.

Life Insurance

Life coverage will be $10,000.

Health Spending Account

The Company will provide a $1,500 per family health spending account allocation, from which the retiree will purchase catastrophic coverage as well as pay for out of pocket medical, dental and vision expenses. No indexation of this spending account is contemplated.

EGD OPEB Plan – Grandfathered Plan

Eligibility

Employees who are eligible to retire under the terms of the pension plan (at age 55) are eligible for post-retirement benefits. Current retirees, surviving spouses, and employees with 60 points (age plus service totals at least 60), as of January 1, 2004 for non-union employees and January 1, 2007 for union employees, will be eligible to elect the grandfathered or non-grandfathered plan.

Spouses and dependants of retirees are eligible for health and dental coverage as well. Dental coverage ceases when the retiree reaches age 65.

On the retiree's death, health and dental coverage continues for the spouse and dependents. Dental coverage ceases when the surviving spouse reaches age 65, and there is no continuation of dental coverage if the surviving spouse is over age 65 when the retiree dies.

Cost Sharing

All costs for retiree benefits are employer paid.

Life Insurance

Group	Pre age 65 coverage	Post age 65 coverage
Non Union	2 x annual earnings at retirement	$5,000
Union	$40,000	$5,000
Part-Time	$15,000	$5,000

Medical and Dental Benefits

Hospital Benefits

- Benefits cover 100% of semi-private room and board charges in excess of charges for ward accommodation and forward-level user fees, where applicable. Hospital charges related to chronic case services are limited to a lifetime maximum of $10,000 per covered person.

Major Medical Benefits

Reimbursement Percentages

- 100% for paramedical practitioners and vision care expenses.
- 90% of first $1,000 of family's eligible expenses per calendar year and 100% of remaining eligible expenses.
- Drug Card with mandatory generic substitution (effective January 1, 2014).

Deductible

- None.

Maximum

- Drugs - $30,000 per person per benefit year.
- All other medical benefits - $50,000 per person in any three consecutive benefit years.

(Prior to January 1, 2014 was $50,000 per person in any three consecutive calendar years for all medical benefits combined).

Eligible Expenses

- Prescription drugs.
- Ambulance services.
- Medical supplies and services (e.g. artificial limbs, orthopaedic shoes).
- Professional services.
- Services of a registered nurse, subject to a lifetime maximum of $5,000.
- Vision care ($100 per person for frames/lenses, $200 for contacts per person every 24 consecutive months).
- Hospital charges for emergency treatment outside Canada.

Provincial Benefits- Ontario Bill 26

- Seniors age 65 and over in Ontario with sufficiently high income are required to pay the first $100 of annual drug costs followed by a $6.11 dispensing fee per prescription. The Plan reimburses retirees for these amounts.

Dental Benefits

Reimbursement Percentages

- 100% of basic expenses.
- 50% of major restorative expenses.
- 50% of orthodontic expenses.

Deductible

- None.

Fee Guide

- Current Provincial Dental Association Fee Guide.

Dental Maximums

- $2,000 per person per calendar year for basic and major restorative expenses combined.
- $1,000 per person lifetime for orthodontic expenses.

EGD OPEB Plan – Non-Grandfathered Plan

Eligibility

Current retirees, surviving spouses, and employees that did not qualify by having 60 points (age plus service totals at least 60) as of January 1, 2004 for non-union employees and January 1, 2007 for union employees will be eligible for the non-grandfathered plan if the employee has at least five years of employment when they retire.

On the retiree's death, the health spending account continues for dependants.

Cost Sharing

With the exception of MSP premiums, all costs for retiree benefits are employer paid.

Life Insurance

Life coverage will be $10,000.

Health Spending Account

The Company will provide a $1,500 per family health spending account allocation, from which the retiree will purchase catastrophic coverage as well as pay for out of pocket medical, dental and vision expenses. No indexation of this spending account is contemplated.

Spectra OPEB Plan - Union Gas Common Plan

Eligibility	
• Retire prior to 2006	Age 55 and retire prior to January 1, 2006 and choose not to participate in the Common Plan
• Retire after 2005	
— Full benefits	Age 55 with 15 years of service; or Age plus service after age 55 greater than 70 points
— Life insurance, extended health benefits and provincial health care premium; no health care spending account	Age 55
— Life insurance, extended health benefits provincial health care premium and reduced health care spending account amount	Age 55 with number of years of service between 1 to 14 at retirement
Life Insurance	$10,000
Medical Benefits	
• Annual deductible	$1,200 per person
• Overall maximum	$500,000 per person lifetime
• Prescription drugs	100%
• Hospital rooms	None
• Ambulance	100%
• Home nursing care	100%, maximum $10,000 per year
• Accidental dental	None
• Psychologist, speech therapist, physiotherapist, chiropractor, massage therapist, naturopath, chiropodist, podiatrist, homeopath and social worker	100%, combined maximum $500 per year for all practitioners
• Other medical items	100% of eligible expenses
• Out of country	None
• Hearing aids	Maximum $500 every 5 years
• Vision care	None
• Survivor benefit	• for spouses under age 65, until the end of the month in which the spouse attains age 65; or • for spouses age 65 and over, for a maximum of 3 months
Dental Care Benefits	No coverage

Spectra OPEB Plan – Union Gas Grandfathered Plan

Eligibility	Age 55 and retire prior to January 1, 2006 and do not choose the Common Plan
Life Insurance	
• Management & Supervisory Employee	2 x annual pre-retirement earnings; amount reduces by 25% of original amount each year to a minimum of $5,000.
• All other employees	$2,500
Medical Benefits	
• Annual deductible	$10 single, $20 family
• Overall maximum	$10,000 per person per year (under age 65); $10,000 per person lifetime (age 65 and over)
• Prescription drugs	100%
• Hospital rooms	100% semi-private
• Ambulance	100%
• Home nursing care	100%, maximum 400 hours lifetime
• Accidental dental	100%
• Psychologist, podiatrist and speech therapist	100%, maximum $200 per year
• Physiotherapist	100%, no maximum
• Massage therapist	100%, maximum $7 per treatment for 12 treatments
• Other medical items	100% of eligible expenses
• Out of country	100%, maximum $10,000 lifetime
• Hearing aids	None
• Vision care	None
• Survivor benefit	For spouses under age 65, until the end of the month in which the spouse attains age 65 or for spouses age 65 and over, for a maximum of 3 months
Dental Care Benefits	
• Coverage	To age 65 only
• Basic	100%
• Major restorative	50%, maximum $5,000 lifetime per person
• Orthodontia	50%, maximum $1,000 lifetime per person
• Survivor benefit	Coverage continues to eligible dependents for 3 months upon the death of retiree
Retiree Supplemental Health Services Plan	
Annual allowance	Management and Supervisory Employees: $75 single, $150 family Other Employees: $50 single, $100 family
Survivor benefit	• For spouses under age 65, until the end of the month in which the spouse attains age 65; or • For spouses age 65 and over, for a maximum of 3 months

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12 January 2023

Subject: Enbridge Gas Inc. Updated Forecasts to 2024 – Reflecting Enbridge Inc.'s Year-end 2022 Financial Reporting

At the request of Enbridge Gas Inc. (the "Company"), we have prepared updated estimates of the Company's share of:

- Enbridge Inc.'s net periodic benefit costs ("accrual costs") and (minimum) cash requirements for fiscal years 2022 to 2024, and
- Enbridge Inc.'s projected balance sheet and accumulated other comprehensive income ("AOCI") for the fiscal years ending 2021 to 2023,

for the pension and benefit plans in which the Company participates. The results in this letter supplement those provided in our report *EGI Pension and Benefit Plans Estimated 2022-2024 Net Periodic Benefit Costs* dated May 2022 (the "Report"). The Report is incorporated by reference into this letter, and is essential to understanding these results.

In the Report, the original forecast results prepared for the Company were based on the economic environment as at April 30, 2022. The purpose of this letter is to provide updated forecasts consistent with Enbridge Inc.'s year-end financial reporting at December 31, 2022. Additional details on the accounting assumptions and methodology which differ from the Report, are provided in Appendix A.

Methodology

We have projected the results of the December 31, 2021 / January 1, 2022 actuarial valuations of the plans for financial reporting purposes forward to each of the years ending 2022 through 2023. The purpose of these projections is to estimate the accounting costs for 2023 through 2024. The projected balance sheet and accumulated other comprehensive income for the fiscal years ending 2021 to 2023, and the corresponding US GAAP accrual costs for the plans over 2022 – 2024 are provided in Appendix B.

We have also projected the results of the December 31, 2021 / January 1, 2022 actuarial valuations of the plans for funding purposes forward to each of the years ending 2023 through 2024. The forecasted actuarial valuations reflect funding discount rates and provisions for adverse deviations applicable as at

November 30, 2022[1]. The projected assets are the same as those used for year-end financial reporting. The purposes of these projections is to estimate the Company's share of the minimum cash funding requirements of the plans for 2022 through 2024. These results are summarized in Appendix C.

Tier II Plans

In mid-October of each year, Enbridge Inc. prepares preliminary estimates of year-end financial reporting. Consistent with prior years, for actual year-end financial reporting at December 31, 2022, Enbridge Inc. relies on these preliminary estimates for the G1, G3, EGD SERP, and SSERP plans (collectively, the "Tier II Plans"). These estimates were based on assumptions as at and asset experience to August 31, 2022.

For the Tier II Plans, the December 31, 2023 balance sheet and 2024 estimated expense are based on market economic conditions at December 31, 2022 and the same projected asset methodology as described for non-Tier II Plans.

Important Notices

We understand this letter may be provided to the Ontario Energy Board (the "OEB") in conjunction with the Company's application for recovery of pension and benefit costs from ratepayers. This letter may not be used or relied upon by any other party or for any other purpose; Mercer is not responsible for the consequences of any unauthorized use.

The results shown in this letter are derived from valuation results shown in the Report, and are subject to the same Important Notices and qualifications described in the Report except as specifically noted in this letter. The Report is incorporated by reference into this letter, and is essential to understanding these results. If you do not have a copy of the Report, please let us know immediately.

These results are based on the same actuarial assumptions used in the Report, except as specifically noted in Appendix A. Our extrapolations reflect a single scenario from a range of possibilities. However, the future is uncertain, and the plans' actual experience will likely differ from the assumptions utilized and the scenarios presented; these differences may be significant or material. This letter is presented at a particular point in time and should not be viewed as a prediction of the plans' future financial condition or their ability to pay benefits in the future. The actuarial methods used in this letter are the same as the Report.

The results shown in this letter are based on the same membership data used in the Report.

To prepare this letter, Mercer has used and relied on financial data submitted by CIBC Mellon without further audit:

- As at November 30, 2022 for all Plans. This asset data was projected to December 31, 2022 with expected cash flows and an estimated rate of return for December 2022 based on asset class benchmarks and target asset allocations. For the Tier II plans this value was only used to calculate the projected asset values at December 31, 2022. And,

[1] At the time this letter was prepared, December 31, 2022 funding discount rates and provisions for adverse deviations were not available. It is expected that the forecasted minimum funding requirements shown in this letter are reasonable estimates of future funding requirements based on available information.

- As at August 31, 2022 only for the Tier II Plans. For the Tier II Plans this asset data was projected to December 31, 2022 with expected cash flows, and a 0% assumed rate of return from August 31 to December 31, 2022. This asset value is reflected in the balance sheet as at December 31, 2022.

The results shown in this letter are based on the same plan provisions as those used in the Report.

The results shown in this letter include projections of plan assets, plan liabilities, and financial reporting accrual costs to a date that is after the date of this letter. Such projections are sensitive to many factors that are unknowable at this time, including (but not limited to) the level of market interest rates, investment performance on the pension funds to the projection date, and other demographic and economic experience over the projection period. As a result, actual amounts in future years will be different from those projected and these differences may be significant or material. Factors such as plan amendments, legislative changes or changes in accounting standards may also be relevant in some cases.

We trust that this letter contains all information you require for filing with the OEB. Please call if you have any additional questions or requests.

Sincerely,

Scott Thompson, FCIA, FSA

January 12, 2023
Date

Edith Samuels, FCIA, FSA

January 12, 2023
Date

Jesse Little, FCIA, FSA

January 12, 2023
Date

Ken Chin, FCIA, FSA

January 12, 2023
Date

Copy:
Robert Rutitis, Elena Chang – Enbridge Gas Inc.
Tyler Brady – Enbridge Inc.
Ben Ukonga – Mercer (Canada) Limited

Appendix A - Methods and Assumptions

Valuation of Plan Assets

To prepare this report, Mercer has used and relied on financial data submitted as at August 31 (for the Tier II Plans) and November 30, 2022 (for all Plans) by CIBC Mellon without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

For purposes of these estimates, we have projected the market values to each year end. In 2022 to capture market experience, we have reflected the actual investment experience from January 1, 2022 to November 30, 2022, and projected the assets to December 31, 2022 using benchmark returns for December 2022. For projections after December 31, 2022, we have used the Enbridge Inc.'s best estimates of annual net asset returns. The rates of return reflected in our projections are as follows[2]:

	Actual asset return (net of all expenses, not annualized)	Estimated asset return (net of all expenses)	
Plan	From January 1, 2022 to November 30, 2022	For December 2022	Annual estimated returns after December 31, 2022
EI RPP	-2.37%	-2.11%	7.10%
EGD RPP	-1.53%	-1.99%	6.70%
Pension Choices	-3.02%	-1.99%	6.60%
EI SPP	-6.58%	-2.67%	4.20%
M&S Plan	-9.23%	-2.41%	5.00%
Salaried Plan	-9.27%	-2.41%	5.00%
BU Plan	-9.23%	-2.41%	5.00%
G1 Plan	-9.39%	-2.41%	5.00%
G3 Plan	-9.37%	-2.41%	5.00%
EGD SERP	-4.41%	-3.48%	3.00%
EGD SSERP	-5.31%	-3.48%	3.00%

Tier II Plans – for December 31, 2022 balances and 2023 expense

In 2022, we have reflected the actual investment experience from January 1, 2022 to August 31, 2022, and projected the assets to December 31, 2022. The rates of return reflected in our projections are as follows:

[2] Applicable for December 31, 2023 balances and 2024 expense for the Tier II Plans.

Plan	Actual asset return (net of all expenses, not annualized) From January 1, 2022 to August 31, 2022	Estimated asset return (net of all expenses) From September 1, 2022 to December 31, 2022
G1 Plan	-11.84%	0.00%
G3 Plan	-11.83%	0.00%
EGD SERP	-6.95%	0.00%
EGD SSERP	-6.99%	0.00%

Estimated future cash flows, including minimum funding contributions have been incorporated into our projections.

Actual assets over year-ends 2022 through 2023 will differ from these estimates.

Actuarial Assumptions – Accounting Basis

The assumptions as at the reporting date are used to determine the present value of the benefit obligation at that date and the net periodic benefit cost for the following year. The actuarial assumptions used in this letter are the same as the Report, except as explicitly noted below. The assumption changes disclosed are for projected December 31, 2022 and 2023 year-ends and the following year's expense[3]:

	Assumptions reflected in this letter		Assumptions previously reflected in the Report	
Plan:	Effective discount rate for benefit obligations	Effective rate of interest on benefit obligations	Effective discount rate for benefit obligations	Effective rate of interest on benefit obligations
• EGD RPP	5.27%	5.21%	4.91%	4.54%
• EI RPP	5.27%	5.25%	4.99%	4.67%
• EI SPP	5.28%	5.23%	4.92%	4.58%
• Pension Choices Plan	5.27%	5.22%	4.93%	4.57%
• M&S Plan	5.26%	5.20%	4.71%	4.37%
• BU Plan	5.26%	5.19%	4.78%	4.38%
• Salaried Plan	5.26%	5.19%	4.78%	4.37%
• G1 Plan	5.26%	5.20%	4.82%	4.44%
• G3 Plan	5.26%	5.20%	4.81%	4.42%
• EGD SERP	5.25%	5.19%	4.75%	4.35%

[3] Applicable for December 31, 2023 balances and 2024 expense for the Tier II Plans.

	Assumptions reflected in this letter		Assumptions previously reflected in the Report	
• EGD SSERP	5.16%	5.14%	4.43%	4.08%
• LSE SERP	5.26%	5.20%	4.82%	4.43%
• EGD OPEB	5.27%	5.23%	4.93%	4.58%
• Spectra OPEB	5.27%	5.22%	4.90%	4.54%
Plan:	**Effective discount rate for current service cost**	**Effective rate of interest on current service cost**	**Effective discount rate for current service cost**	**Effective rate of interest on current service cost**
• EGD RPP	5.25%	5.23%	5.08%	4.92%
• EI RPP	5.26%	5.21%	5.06%	4.83%
• EI SPP	5.28%	5.23%	5.02%	4.81%
• Pension Choices Plan	5.26%	5.26%	5.06%	4.91%
• Legacy Spectra Closed Plans	N/A	N/A	N/A	N/A
• EGD SERP, EGD SSERP and LSE SERP	N/A	N/A	N/A	N/A
• EGD OPEB	5.27%	5.27%	5.09%	5.00%
• Spectra OPEB	5.27%	5.27%	5.08%	4.99%

Tier II Plans – for December 31, 2022 balances and 2023 expense

	Assumptions reflected in this letter		Assumptions previously reflected in the Report	
Plan:	**Effective discount rate for benefit obligations**	**Effective rate of interest on benefit obligations**	**Effective discount rate for benefit obligations**	**Effective rate of interest on benefit obligations**
• G1 Plan	4.95%	4.89%	4.82%	4.44%
• G3 Plan	4.95%	4.89%	4.81%	4.42%
• EGD SERP	4.95%	4.84%	4.75%	4.35%
• EGD SSERP	4.88%	4.77%	4.43%	4.08%

Expected long-term rate of return on assets:		
• EGD RPP	6.70% per year	7.10% per year
• EI RPP	7.10% per year	7.60% per year
• EI SPP	4.20% per year	5.10% per year
• Pension Choices Plan	6.60% per year	7.00% per year
• M&S, Salaried Plan, BU Plan, G1 and G3	5.00% per year	5.60% per year
• EGD SERP & SSERP	3.00% per year	3.30% per year
Post-retirement indexation	Based on the contractual indexation provisions of the applicable plan and assumed inflation of 3.90% in 2023, trending down to 2.00% per year for 2027 and after Actual 2022 contractual inflationary increase rates were available and reflected in the projected benefit payments and benefit obligations	Based on the contractual indexation provisions of the applicable plan and assumed inflation of 4.50% in 2022, trending down to 2.00% per year for 2026 and after
Actuarial basis for benefits to be settled through a lump sum:	Discount rate: 4.25% Mortality rates: CPM2014 with fully generational improvements using CPM-B	Discount rate: 3.50% Mortality rates: CPM2014 with fully generational improvements using CPM-B

Rationale for significant economic and demographic assumptions selected with the advice of the actuary

A rationale for each of the significant updated economic assumptions used to measure pension obligations is provided below:

- The discount rate was derived from the Mercer model. The Mercer model is based on actual AA corporate bond yield data for short term yields and extrapolated data for longer terms. Under the Mercer model, the Plans' projected benefit payments are matched against a series of spot rates derived from a yield to maturity curve.

- A short-term load has been included with the inflation assumption. The initial load is derived from prevailing inflation rates that are currently exceeding the Bank of Canada ("BoC") target range. The duration of the load, and convergence back to the 2% long-term assumption, is based on statements from the BoC, as well as other macroeconomic forecasts, which expect inflation to persist at elevated levels over the short-term before returning to the 2% BoC target within a few years.

- The cost of future lump sums will depend on the level of market interest rates at the time the lump sum is paid and any changes in the applicable actuarial standards for the determination of pension plan commuted values. The assumed cost of future lump sums is based on the average expected level of market interest rates over the period during which lump sums are expected to be paid, taking into account market conditions on the valuation date.

Assessment of reasonableness for significant economic and demographic assumptions not selected with the advice of the actuary

The expected rate of return on plan assets is selected by Enbridge Inc. To assess the reasonableness of this assumption, we compared the selected assumption to the range of acceptable values for the assumption. Specifically:

- A reasonable range for the expected rate of return on plan assets for each plan is based on:
  - The values between the 35th percentile and 65th percentile of simulated investment returns using estimated returns for each major asset class consistent with market conditions on the valuation date, the expected time horizon over which benefits are expected to be paid, and the target asset mix specified in the Plans' investment policy.
  - Additional returns assumed to be achievable due to active equity management, equal to the fees related to active equity management. Such fees were determined as the difference between the provision for total investment expenses and the hypothetical fees that would be incurred for passive management of all assets.
  - Implicit provision for investment and non-investment expenses determined as the average rate of expenses paid from the fund over the last three years.

The selected expected return on plan assets for each plan falls within the above reasonable range.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. The actuarial assumptions used in this letter are the same as the Report, except as explicitly noted below.

Assumption	Determined as at November 30, 2022
Discount rate:	
• EGD RPP	6.60% per year
• EI RPP	7.05% per year
• EI SPP	4.20% per year
• Pension Choices Plan	6.55% per year
• Legacy Spectra Closed Plans	5.45% per year
• EGD SERP and EGD SSERP	3.00% per year

The assumptions are best-estimate and do not include a margin for adverse deviations.

Provision for Adverse Deviations

The provision for adverse deviations has been established in accordance with Ontario regulations as at November 30, 2022 taking into account the following parameters:

Provision for Adverse Deviations	EGD RPP	EI RPP	Pension Choices Plan	Legacy Spectra Closed Plans
i) 5.0% for a closed plan and 4.0% for a plan that is not a closed plan	5.00%	4.00%	5.00%	5.00%
ii) Provision based on combined target asset allocation for non-fixed Income assets	6.00%	4.50%	6.00%	4.00%
iii) Adjustment for expected returns in excess of the Benchmark Discount Rate	0.00%	1.20%	0.00%	0.00%
Provision for Adverse Deviations (i. + ii. + iii.)	11.00%	9.70%	11.00%	9.00%

Actuarial Assumptions – Hypothetical Wind-up Basis

A hypothetical wind-up valuation was performed only for the EI RPP. The actuarial assumptions and methods used in this letter are the same as the Report, except as explicitly noted below:

The assumptions are as follows:

Basis for Benefits Assumed to be Settled Through a Lump Sum	
Non-indexed interest rates:	4.50% per year for 10 years, 5.00% per year thereafter
Inflation rates:	2.00% per year for 10 years, 2.00% per year thereafter
Basis for Benefits Assumed to be Settled Through the Purchase of an Annuity	
Non-indexed interest rate:	4.48% per year (based on a duration of 13.2)
Partially-indexed interest rate:	2.61% per year, applicable to benefits subject to contractual post-retirement indexing
Other Assumptions	
Maximum pension limit:	$3,420.00 in 2022 increasing at 2.87% per year

Appendix B – Financial Reporting Results

Projected future accrual costs

We have projected the results of the December 31, 2021 / January 1, 2022 actuarial valuations of the plans for financial reporting purposes forward to each of the years ending 2022 through 2023. The purpose of these projections is to estimate the accounting costs for 2023 through 2024. The projections are based on the economic environment as at December 31, 2022[4] and assumptions described in Appendix A. **Where projections have been made, actual plan experience may differ significantly from the assumptions used in the projections.**

The projected balance sheet and accumulated other comprehensive income for the fiscal years ending 2021 to 2023 are summarized below.

Company's Share US GAAP ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried	Group 1	Group 3
December 31, 2021								
Fair value of plan assets	161,408	1,187,366	578,449	179,522	169,633	75,041	10,492	10,678
Benefit obligation	211,785	1,097,187	605,735	156,840	139,053	61,785	9,023	8,371
Funded status (plan assets less benefit obligations)	**(50,377)**	**90,179**	**(27,286)**	**22,682**	**30,580**	**13,256**	**1,468**	**2,308**
Prior service credit (cost)	-	-	-	-	-	-	-	-
Net gain (loss)	13,618	(214,077)	(55,476)	(3,051)	(1,276)	(2,320)	(226)	(440)
Accumulated other comprehensive income (loss)	13,618	(214,077)	(55,476)	(3,051)	(1,276)	(2,320)	(226)	(440)
Accumulated contributions in excess of net periodic benefit cost	(63,995)	304,256	28,191	25,733	31,856	15,576	1,694	2,748
Net amount [surplus (deficit)] recognized in statement of financial position	(50,377)	90,179	(27,286)	22,682	30,580	13,256	1,468	2,308
December 31, 2022								
Fair value of plan assets	199,321	1,094,723	525,200	149,077	141,353	62,359	8,843	9,043
Benefit obligation	195,591	869,368	451,348	122,933	108,047	48,401	7,176	6,557
Funded status (plan assets less benefit obligations)	**3,731**	**225,355**	**73,852**	**26,144**	**33,306**	**13,958**	**1,668**	**2,485**
Prior service credit (cost)	-	-	-	-	-	-	-	-
Net gain (loss)	79,451	(113,188)	25,224	(4,418)	(3,379)	(3,745)	(311)	(574)
Accumulated other comprehensive income (loss)	79,451	(113,188)	25,224	(4,418)	(3,379)	(3,745)	(311)	(574)
Accumulated contributions in excess of net periodic benefit cost	(75,720)	338,543	48,628	30,562	36,685	17,703	1,979	3,060
Net amount [surplus (deficit)] recognized in statement of financial position	3,731	225,355	73,852	26,144	33,306	13,958	1,668	2,485
December 31, 2023								
Fair value of plan assets	222,163	1,111,783	532,806	145,543	138,576	61,019	8,801	9,043
Benefit obligation	241,647	862,702	448,368	118,281	103,821	46,479	6,806	6,213
Funded status (plan assets less benefit obligations)	**(19,483)**	**249,081**	**84,438**	**27,262**	**34,755**	**14,540**	**1,995**	**2,830**
Prior service credit (cost)	-	-	-	-	-	-	-	-
Net gain (loss)	83,266	(113,491)	25,032	(4,379)	(3,396)	(3,772)	(75)	(361)
Accumulated other comprehensive income (loss)	83,266	(113,491)	25,032	(4,379)	(3,396)	(3,772)	(75)	(361)
Accumulated contributions in excess of net periodic benefit cost	(102,751)	362,572	59,406	31,640	38,151	18,313	2,070	3,191
Net amount [surplus (deficit)] recognized in statement of financial position	(19,483)	249,081	84,438	27,262	34,755	14,540	1,995	2,830

[4] August 31, 2022 for the results shown for the December 31, 2022 balance sheet and 2023 projected expense for the Tier II Plans.

Company's Share US GAAP ('000s)	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
December 31, 2021							
Fair value of plan assets	14,927	8,075	19,766	-	-	2,415,357	2,415,357
Benefit obligation	14,815	3,438	22,371	54,968	156,706	2,385,371	2,542,077
Funded status (plan assets less benefit obligations)	**113**	**4,638**	**(2,605)**	**(54,968)**	**(156,706)**	**29,988**	**(126,718)**
Prior service credit (cost)	-	-	-	-	(275)	-	(275)
Net gain (loss)	(4,197)	22	(389)	(11,867)	12,038	(279,679)	(267,641)
Accumulated other comprehensive income (loss)	(4,197)	22	(389)	(11,867)	11,763	(279,679)	(267,916)
Accumulated contributions in excess of net periodic benefit cost	4,309	4,616	(2,215)	(43,101)	(168,469)	309,668	141,199
Net amount [surplus (deficit)] recognized in statement of financial position	113	4,638	(2,605)	(54,968)	(156,706)	29,988	(126,718)
December 31, 2022							
Fair value of plan assets	13,073	7,241	17,028	-	-	2,227,261	2,227,261
Benefit obligation	12,406	2,963	18,319	42,775	119,442	1,885,884	2,005,326
Funded status (plan assets less benefit obligations)	**668**	**4,278**	**(1,291)**	**(42,775)**	**(119,442)**	**341,379**	**221,937**
Prior service credit (cost)	-	-	-	-	(302)	-	(302)
Net gain (loss)	(3,543)	(510)	1,848	(1,201)	49,680	(24,346)	25,334
Accumulated other comprehensive income (loss)	(3,543)	(510)	1,848	(1,201)	49,378	(24,346)	25,032
Accumulated contributions in excess of net periodic benefit cost	4,211	4,788	(3,139)	(41,575)	(168,820)	365,725	196,905
Net amount [surplus (deficit)] recognized in statement of financial position	668	4,278	(1,291)	(42,775)	(119,442)	341,379	221,937
December 31, 2023							
Fair value of plan assets	12,802	7,135	18,789	-	-	2,268,460	2,268,460
Benefit obligation	11,608	2,650	19,369	41,907	119,604	1,909,851	2,029,455
Funded status (plan assets less benefit obligations)	**1,194**	**4,485**	**(580)**	**(41,907)**	**(119,604)**	**358,610**	**239,006**
Prior service credit (cost)	-	-	-	-	(328)	-	(328)
Net gain (loss)	(2,968)	(383)	1,837	(1,204)	45,897	(19,894)	26,003
Accumulated other comprehensive income (loss)	(2,968)	(383)	1,837	(1,204)	45,569	(19,894)	25,675
Accumulated contributions in excess of net periodic benefit cost	4,161	4,868	(2,417)	(40,702)	(165,173)	378,502	213,329
Net amount [surplus (deficit)] recognized in statement of financial position	1,194	4,485	(580)	(41,907)	(119,604)	358,610	239,006

Based on the projected financial positions, the resulting US GAAP accrual costs for the plans over 2022 – 2024 are summarized below.

Company's Share US GAAP ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried	Group 1	Group 3
2022								
DB Current service cost (employer)	52,553	6,245	208	-	-	-	-	-
Interest cost	6,479	29,493	16,708	3,877	3,406	1,515	207	188
Expected return on plan assets	(13,139)	(77,801)	(37,320)	(8,706)	(8,235)	(3,643)	(491)	(500)
Amortization of past service costs	-	-	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	-	7,775	-	-	-	-	-	-
Total DB Net Periodic Benefit Cost	45,893	(34,288)	(20,404)	(4,829)	(4,829)	(2,128)	(284)	(312)
DC Current Service Cost	2,547	69	294	-	-	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**48,440**	**(34,219)**	**(20,110)**	**(4,829)**	**(4,829)**	**(2,128)**	**(284)**	**(312)**
2023								
DB Current service cost (employer)	31,334	3,532	138	-	-	-	-	-
Interest cost	10,146	43,911	22,884	6,108	5,362	2,400	338	308
Expected return on plan assets	(14,450)	(71,522)	(33,799)	(7,186)	(6,828)	(3,009)	(429)	(440)
Amortization of past service costs	-	-	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	-	51	-	-	-	-	-	-
Total DB Net Periodic Benefit Cost	27,030	(24,028)	(10,777)	(1,078)	(1,466)	(609)	(91)	(132)
DC Current Service Cost	3,409	72	266	-	-	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**30,439**	**(23,956)**	**(10,511)**	**(1,078)**	**(1,466)**	**(609)**	**(91)**	**(132)**
2024								
DB Current service cost (employer)	30,879	3,463	129	-	-	-	-	-
Interest cost	12,531	43,518	22,719	5,869	5,144	2,300	340	310
Expected return on plan assets	(16,028)	(72,618)	(34,294)	(7,013)	(6,693)	(2,944)	(427)	(440)
Amortization of past service costs	-	-	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	-	-	-	-	-	-	-	-
Total DB Net Periodic Benefit Cost	27,382	(25,637)	(11,446)	(1,144)	(1,549)	(644)	(87)	(130)
DC Current Service Cost	4,149	74	246	-	-	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**31,531**	**(25,563)**	**(11,200)**	**(1,144)**	**(1,549)**	**(644)**	**(87)**	**(130)**

Company's Share US GAAP ('000s)	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
2022							
DB Current service cost (employer)	-	-	1,212	-	1,833	60,218	62,051
Interest cost	311	56	631	1,440	4,252	64,311	68,563
Expected return on plan assets	(417)	(228)	(932)	-	-	(151,412)	(151,412)
Amortization of past service costs	-	-	-	-	(27)	-	(27)
Amortization of net actuarial loss (gain)	204	-	12	38	(922)	8,029	7,107
Total DB Net Periodic Benefit Cost	98	(172)	923	1,478	5,136	(18,854)	(13,718)
DC Current Service Cost	-	-	-	-	-	2,910	2,910
Total (DB & DC) Net Periodic Benefit Cost	**98**	**(172)**	**923**	**1,478**	**5,136**	**(15,944)**	**(10,808)**
2023							
DB Current service cost (employer)	-	-	885	-	1,144	35,889	37,033
Interest cost	574	131	937	2,151	6,057	95,250	101,307
Expected return on plan assets	(376)	(211)	(737)	-	-	(138,987)	(138,987)
Amortization of past service costs	-	-	-	-	(27)	-	(27)
Amortization of net actuarial loss (gain)	169	-	-	-	(3,731)	220	(3,511)
Total DB Net Periodic Benefit Cost	367	(80)	1,085	2,151	3,443	(7,628)	(4,185)
DC Current Service Cost	-	-	-	-	-	3,747	3,747
Total (DB & DC) Net Periodic Benefit Cost	**367**	**(80)**	**1,085**	**2,151**	**3,443**	**(3,881)**	**(438)**
2024							
DB Current service cost (employer)	-	-	907	-	1,144	35,378	36,522
Interest cost	573	126	989	2,105	6,063	96,524	102,587
Expected return on plan assets	(372)	(208)	(809)	-	-	(141,846)	(141,846)
Amortization of past service costs	-	-	-	-	(27)	-	(27)
Amortization of net actuarial loss (gain)	138	-	-	-	(3,476)	138	(3,338)
Total DB Net Periodic Benefit Cost	339	(82)	1,087	2,105	3,704	(9,806)	(6,102)
DC Current Service Cost	-	-	-	-	-	4,469	4,469
Total (DB & DC) Net Periodic Benefit Cost	**339**	**(82)**	**1,087**	**2,105**	**3,704**	**(5,337)**	**(1,633)**

Appendix C - Projected Future Cash

We have projected the results of the December 31, 2021 / January 1, 2022 actuarial valuations of the plans for funding purposes forward to each of the years ending 2023 through 2024. The purposes of these projections is to estimate the Company's share of the minimum cash funding requirements of the plans for 2022 through 2024. The projections are based on the economic environment as at December 31, 2022 and assumptions described in Appendix A.

Where projections have been made, actual plan experience may differ significantly from the assumptions used in the projections.

Based on the projected going concern and solvency positions, the resulting minimum funding requirements for the plans over 2022 – 2024 are summarized below.

Company's Share Projected Contributions ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried	Group 1	Group 3
2022								
DB Current Service Cost	25,045	-	33	-	-	-	-	-
DC Current Service Cost	2,547	69	294	-	-	-	-	-
Going Concern Special Payments	-	-	-	-	-	-	-	-
Solvency Special Payments	9,124	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	-	-	-
Total	**36,716**	**69**	**327**	**-**	**-**	**-**	**-**	**-**
2023								
DB Current Service Cost	-	-	-	-	-	-	-	-
DC Current Service Cost	3,409	72	266	-	-	-	-	-
Going Concern Special Payments	-	-	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	-	-	-
Total	**3,409**	**72**	**266**	**-**	**-**	**-**	**-**	**-**
2024								
DB Current Service Cost	-	-	-	-	-	-	-	-
DC Current Service Cost	4,149	74	246	-	-	-	-	-
Going Concern Special Payments	-	-	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	-	-	-
Total	**4,149**	**74**	**246**	**-**	**-**	**-**	**-**	**-**

Company's Share Projected Contributions ('000s)	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
2022							
DB Current Service Cost	-	-	-	-	-	25,078	25,078
DC Current Service Cost	-	-	-	-	-	2,910	2,910
Going Concern Special Payments	-	-	67	-	-	67	67
Solvency Special Payments	-	-	-	-	-	9,124	9,124
Direct Benefit Payments	-	-	-	3,004	4,785	3,004	7,789
Total	**-**	**-**	**67**	**3,004**	**4,785**	**40,183**	**44,968**
2023							
DB Current Service Cost	-	-	1,042	-	-	1,042	1,042
DC Current Service Cost	-	-	-	-	-	3,747	3,747
Going Concern Special Payments	317	-	848	-	-	1,165	1,165
Solvency Special Payments	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	3,023	7,090	3,023	10,113
Total	**317**	**-**	**1,890**	**3,023**	**7,090**	**8,977**	**16,067**
2024							
DB Current Service Cost	-	-	1,068	-	-	1,068	1,068
DC Current Service Cost	-	-	-	-	-	4,469	4,469
Going Concern Special Payments	317	-	833	-	-	1,150	1,150
Solvency Special Payments	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	3,032	7,153	3,032	10,185
Total	**317**	**-**	**1,901**	**3,032**	**7,153**	**9,719**	**16,872**

Summary of Utility O&M Cost Drivers - 2020 vs 2019

Line No.	Particulars	$ millions	Comments
		(a)	(b)
1	2019 Actual	914.6	
2	Salaries & Wages	(28.2)	Decline in FTEs from the VWO program and lower overtime from reduced work volumes due to COVID-19 impacts.
3	Contract Services	(26.6)	Savings from postage from ebill adoption, aviation contract cancellation, reduced work volumes due to COVID-19 impacts on IMP and field work (locates and meters), offset by pressures from lead remediation, cross bores and corrosion work.
4	Materials & Supplies	(1.3)	Hydro cost savings from storage's use of generators to power stations on peak usage days.
5	Fleet & Fuel	(2.3)	Lower cost of fuel and lower fuel usage due to work and travel limitations resulting from COVID-19.
6	Bad Debt	1.7	Higher arrears from economic factors impacting customers due to COVID-19.
7	Rents & Leases	0.3	
8	Sponsorships & Memberships	(3.9)	Limited sponsorship opportunities during COVID-19.
9	Major Projects	(0.4)	
10	Other O&M	9.0	Operations COVID-19 cost pressures - downtime/standby, emergency response resources and janitorial services/personal protective equipment.
11	Central Functions	7.3	Various small changes in CF departmental costs.
12	Business Unit Benefits	(10.0)	Changes in pension (actuarial valuations), incentive pay (performance metrics) and other benefits (insurance/medical trends and FTEs).
13	Overhead Capitalization	12.9	Decrease in capitalization from lower gross Operations and Engineering & STO O&M offset by the implementation of the harmonized overhead capitalization methodology.
14	Integration-Related Costs	72.4	Integration initiatives as a result of amalgamation.
15	Demand Side Management	2.9	
16	2020 Actual	948.4	

Summary of Utility O&M Cost Drivers - 2021 vs 2020

Line No.	Particulars	$ millions	Comments
		(a)	(b)
1	2020 Actual	948.4	
2	Salaries & Wages	5.3	Increase due to merit, Operations overtime related to a gradual increase in work volumes due to COVID-19 impacts, Customer Care overtime for CIS implementation offset by Work & Resource Strategy FTE reductions.
3	Contract Services	11.0	Gradual increase in work volumes due to COVID-19 impacts related to planned inspections from IMP risk modelling and locates, increased cross bores, Extended Alliance alignment for Work & Resource Strategy and inflationary pressures offset by prior year lead remediation.
4	Materials & Supplies	2.3	Material write off for inventory obsolescence and project cancellation.
5	Fleet & Fuel	5.2	Increased vehicle maintenance and rental costs from higher fuel costs and supply chain issues due to COVID-19.
6	Bad Debt	2.5	Higher arrears from inflation, consumer indebtedness and unemployment rates due to COVID-19 induced market conditions.
7	Rents & Leases	1.2	Increase in easement costs resulting from higher land valuations.
8	Sponsorships & Memberships	3.1	Greater community needs and the ramping up of activities with the easing of COVID-19 restrictions.
9	Major Projects	(0.2)	
10	Other O&M	(4.2)	Unapplied customer payments, lower downtime/standby, emergency response resources and janitorial services/personal protective equipment from easing of COVID-19 restrictions offset by an increase to travel, training and other employee expenses.
11	Central Functions	35.2	TIS ('as a service' model, cyber security, sustainment) and CF benefits from higher pension, STIP, LTIP and improved identification of BU and CF benefit split.
12	Business Unit Benefits	(5.1)	Changes in pension (actuarial valuations), incentive pay (performance metrics) and other benefits (insurance/medical trends and FTEs).
13	Overhead Capitalization	(9.9)	Increase in capitalization from higher capital expenditures influencing overhead capitalization rates per the harmonized methodology and higher gross O&M for Operations, Engineering & STO, and CF.
14	Integration-Related Costs	(74.3)	Completion or wind down of initiatives.
15	Demand Side Management	(0.2)	
16	2021 Actual	920.6	

Summary of Utility O&M Cost Drivers - 2022 vs 2021

Line No.	Particulars	$ millions	Comments
		(a)	(b)
1	2021 Actual	920.6	
2	Salaries & Wages	23.1	Increase due to merit and FTEs for BD&R, Customer Care, Operations (gradual increase in work volumes and reduction in backlog of work due to COVID-19 impacts), ES and Engineering & STO.
3	Contract Services	30.5	Gradual increase in work volumes and reduction in backlog of work due to COVID-19 impacts, locate costs from impact of Bill 93, cross bores, IMP based on risk modelling enhancements, support for call volumes and inflationary pressures offset by savings from the CIS integration.
4	Materials & Supplies	(0.7)	
5	Fleet & Fuel	2.9	Higher fuel costs and usage as work volumes increase due to COVID-19 impacts.
6	Bad Debt	0.9	Higher arrears from consumer indebtedness caused by higher inflation and other economic factors as well as larger customer bills due to a colder winter and commodity prices.
7	Rents & Leases	1.7	Increase in easement costs resulting from higher land valuations.
8	Sponsorships & Memberships	(2.4)	Decrease in 2022 following a ramp-up of activities in late 2021.
9	Major Projects	2.0	Increase from merit and FTEs to support construction and engineering work.
10	Other O&M	17.3	Accounting presentation change for damage recoveries (moved to other revenue), prior year unapplied customer payments and increase to travel, training and other employee expenses offset by reduction in Operations' COVID-19 direct costs.
11	Central Functions	56.9	TIS ('as a service' model, cyber security, sustainment) and various departmental increases.
12	Business Unit Benefits	(39.6)	Lower pension (actuarial valuations) and STIP (assumed typical performance metrics).
13	Overhead Capitalization	(34.7)	Increase in capitalization from higher gross O&M for Operations, Engineering & STO, and CF.
14	Integration-Related Costs	(14.6)	Completion or wind down of initiatives.
15	Demand Side Management	0.0	
16	2022 Estimate	963.8	

Summary of Utility O&M Cost Drivers - 2023 vs 2022

Line No.	Particulars	$ millions	Comments	
		(a)	(b)	
1	2022 Estimate	963.8		
2	Salaries & Wages	13.1	Increase due to merit and FTEs for BD&R, Customer Care, Operations, ES and Engineering & STO offset by embedded productivity.	
3	Contract Services	18.1	Increase in locate costs from impacts of Bill 93, cross bores, IMP based on risk modelling enhancements, environmental and integrity programs, rebasing application costs, support for call volumes and contract market growth, and inflationary pressures offset by embedded productivity.	
4	Materials & Supplies	(0.9)		
5	Fleet & Fuel	0.3		
6	Bad Debt	3.4	Higher arrears from consumer indebtedness caused by the prolonged effect of higher commodity prices, inflation and other economic factors.	
7	Rents & Leases	0.3		
8	Sponsorships & Memberships	2.1	Increase to typical annual expenditure based on community needs and opportunities.	
9	Major Projects	0.2		
10	Other O&M	9.7	Insurance strategy impact to Operations (offset by lower premiums in CF) and increase to travel, training and other employee expenses offset by unapplied customer payments.	/u
11	Central Functions	16.2	TIS ('as a service' model, cyber security, sustainment) offset by insurance premium reduction.	/u
12	Business Unit Benefits	8.1	Higher pension (actuarial valuations), STIP and other benefits (FTE growth and inflation), partially offset by lower amortization of Union's pre-amalgamation actuarial losses.	/u
13	Overhead Capitalization	(32.2)	Increase in capitalization from 1) a higher proportion of capital activity leading to an increase in capitalization rates and labour burden and 2) the increase in gross O&M projections.	
14	Integration-Related Costs	(15.7)	Completion or wind down of initiatives.	
15	Demand Side Management	35.1		/u
16	2023 Bridge Year	1,021.7		/u

Summary of Utility O&M Cost Drivers - 2024 vs 2023

Line No.	Particulars	$ millions	Comments	
		(a)	(b)	
1	2023 Bridge Year	1,021.7		/u
2	Salaries & Wages	17.0	Increase due to merit, FTEs for BD&R, Customer Care, ES and Engineering & STO, cost previously captured in IRPOCDA and GHGEADA offset by embedded productivity.	
3	Contract Services	3.8	Increase in locate costs from impacts of Bill 93, cross bores, costs previously captured in OEBCAVA and inflationary pressures offset by embedded productivity.	
4	Materials & Supplies	0.5	Inflation increase.	
5	Fleet & Fuel	0.3	Inflation increase.	
6	Bad Debt	4.0	Higher arrears from consumer indebtedness caused by the prolonged effect of higher commodity prices, inflation and other economic factors.	
7	Rents & Leases	0.2	Inflation increase.	
8	Sponsorships & Memberships	0.2	Inflation increase.	
9	Major Projects	0.1	Inflation increase.	
10	Other O&M	(4.4)	Removal of Rate 325 and implementation a non-utility cross charge for Dow Moore/Black Creek and implementation of the harmonized unregulated allocation methodology offset by the proposal to treat DCB and DPAC as a utility activity and previous year's reduction from unapplied customer payments.	/u
11	Central Functions	24.2	TIS ('as a service' model, cyber security, sustainment) and depreciation allocation for Oracle Cloud implementation.	/u
12	Business Unit Benefits	(0.7)	Lower pension (actuarial valuations) and lower amortization of Union's pre-amalgamation actuarial losses.	/u
13	Overhead Capitalization	(9.3)	Increase in capitalization from a higher proportion of capital activity leading to an increase in capitalization rates and labour burden, and an increase in gross O&M.	
14	Integration-Related Costs	(19.5)	Completion of initiatives.	
15	Demand Side Management	7.9		/u
16	2024 Test Year	1,046.0		/u

PROGRAM DELIVERY COSTS WITH VARIANCE ANALYSIS

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1. The purpose of this evidence is to present operating & maintenance (O&M) costs for discrete program areas as provided in Section 2.4.3.3 of the OEB's Filing Requirements[1].

2. This evidence is organized as follows:
    1. Workforce Planning and Employee Compensation
    2. Shared Services and Corporate Cost Allocation
    3. Purchase of Non-Affiliate Services
    4. One-Time Costs
    5. Low-Income Programs
    6. Charitable and Political Donations

1. Workforce Planning and Employee Compensation

3. This section provides a historical, harmonized representation of full-time equivalents (FTEs) and compensation costs for EGD, Union, and Enbridge Gas from 2013 to the 2024 Test Year with high-level explanations of the changes over that period. In addition, changes in the Company's compensation program since the 2013 Cost of Service Applications will be described. Finally, supporting studies will be provided to

[1] Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p. 28.

substantiate the pension and benefit programs and compare Enbridge Gas's compensation relative to peer organizations.

4. Table 1 provides FTEs for EGD, Union, and Enbridge Gas from 2013 to the 2024 Test Year. Amalgamation in 2019 combined the employee bases at each of EGD and Union together as Enbridge Gas. Each utility used a slightly different way of aggregating FTEs. While both included regular full-time and part-time employees, and consistently excluded contractors, they differed in that EGD included temporary employees (while Union did not), and Union included employees on leave (while EGD did not). A harmonized definition of FTEs is now in place which consists of regular full-time and part-time employees, and temporary full-time and part-time employees. Contractors and employees on leave are not included in the harmonized definition of FTEs. The harmonized definition of FTEs allows for consistency of historical EGD and Union FTEs from 2013 to 2018, along with appropriately depicting the centralization that commenced in 2018.

Table 1

Employees - Full Time Equivalents

Line No.	Particulars ($ millions)	Utility	EGD - Business Unit (1)	Union - Business Unit (1)	Business Unit (1)(2)	Central Functions (1)(3)
			(a)	(b)	(c)	(d)
1	2013 Actual	EGD/Union	2,206	2,182		
2	2014 Actual	EGD/Union	2,194	2,220		
3	2015 Actual	EGD/Union	2,130	2,253		
4	2016 Actual	EGD/Union	2,063	2,272		
5	2017 Actual	EGD/Union	1,934	2,239		
6	2018 Actual	EGD/Union	1,639	1,810		691
7	2019 Actual	EGI			3,229	569
8	2020 Actual	EGI			2,946	526
9	2021 Actual	EGI			3,013	503
10	2022 Estimate	EGI			3,346	563
11	2023 Bridge Year	EGI			3,507	546
12	2024 Test Year	EGI			3,470	546

Notes:

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

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

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

5. Both EGD and Union maintained a comparable level of FTEs in 2013. Starting in 2014, FTEs started to diverge with EGD declining by 272 FTEs by 2017. The reduction in FTEs was driven by the rationalization of redundant roles as well as a restructuring initiative that targeted organizational layers and span of control to drive process and system efficiencies. Over the same 2013 to 2017 period, Union

increased by 57 FTEs largely due to significant capital expansion of storage and transmission assets.

6. The reduction of EGD and Union FTEs in 2018 was largely the result of centralization brought about by the Enbridge and Spectra Energy Corp (Spectra) merger. FTEs in the areas of Human Resources (HR), Technology Information Systems (TIS), and Finance are examples of the larger functional groups that were transferred to Central Functions (CF).

7. In 2019, the Enbridge Gas amalgamation and the subsequent organizational restructuring resulted in a decrease of 220 business unit FTEs. The reduction of business unit FTEs in 2020 was largely due to the Voluntary Workforce Options (VWO) program which incentivized employees to retire early, take leave or voluntarily exit (please see Exhibit 1, Tab 9, Schedule 1 for more information). The VWO program led to swifter role rationalization by advancing resourcing reductions that were expected over the amalgamation period leading up to rebasing.

8. Amalgamation also initiated integration activities which required dedicated and specialized resources. Within the business unit FTEs provided in Table 1, FTEs dedicated to integration work are approximately 35 in 2019, 60 in 2020, 85 in 2021 and expected to peak at 185 in 2022. As integration activities reach completion, 2023 will see a reduction of approximately 115 FTEs dedicated to integration with the remaining 70 FTEs being eliminated in 2024.

9. Several of the key trends and drivers provided at Exhibit 4, Tab 4, Schedule 2, will require incremental FTE additions beginning in 2022, continuing into 2023 and sustained for 2024. While all business unit departments have FTE additions, Distribution Operations and Engineering and Storage & Transmission Operations

account for most of the growth occurring between the 2021 actual FTEs of 3,013 (2,928 excluding integration FTEs noted in the preceding paragraph) and the 2024 Test Year FTEs of 3,470.

10. From the end of 2021 to 2024, Distribution Operations expects to add approximately 282 FTEs. These FTE additions address COVID-19 induced labour shortages, turnover and attrition, reflecting the resource requirements for the transition to pre COVID-19 work volume and to address the backlog of deferred work caused by COVID-19 restrictions. In addition, these resources will support the integrity programs outlined in the Asset Management Plan and support customer additions.

11. Engineering and Storage & Transmission Operations expects to add 150 FTEs to support several initiatives. First, support of capital initiatives related to system improvement, storage, engineering, and hydrogen blending will require 59 FTEs. Second, support for compliance activities, such as the Enbridge Integrity Management Framework Standard (IMFS), environmental program, storage maintenance requirements, quality management and training sustainment and TSA guidelines for cyber security will require 35 FTEs. Third, the maximum operating pressure (MOP) verification program scope expansion to include Union pipelines will require 8 FTEs. Finally, the remaining FTEs will address COVID-19 induced labour shortages, turnover and attrition.

12. Customer Care expects to add 46 FTEs. This increase is primarily made up of 35 FTEs expected to provide customer support by addressing increased call volumes, call audits and billing volumes resulting from the Company’s growing customer base. The remaining FTE increase is related to various initiatives such as support

for growth in contract market customers, the Ontario government's Green Button Program and Community Expansion.

13. Business Development & Regulatory (BD&R) and Energy Services are expecting FTE increases of 38 and 16, respectively. For BD&R, 23 FTE additions are related to integrated resource planning (IRP) and compliance with federal and provincial GHG emission regulations previously accounted for under the IRP Operating Costs Deferral Account (IRPOCDA) and the GHG Emissions Administration Deferral Account (GHGEADA). The remaining FTE additions for BD&R are related to energy transition, implementation of the rebasing decision, Business Development initiatives, the Greener Homes initiative funded by the Natural Resources Canada (NRCan) and address turnover and attrition. For Energy Services, the 16 FTE additions are spread across multiple initiatives such as support for integrity management of storage wells and reservoir assets, oversight of storage and transportation enhancement initiatives, support for Gas Control including outage responsibilities and cyber security enhancements, energy transition and ongoing portfolio management activities.

14. Demand Side Management (DSM) is expected to add 10 FTEs. The base salary costs associated with these FTEs are included in the Company's multi-year DSM Plan Application[2] that was filed with the OEB on May 3, 2021, and are a pass-through component of utility O&M.

15. During the deferred rebasing term, Enbridge Gas has remained cognisant of its commitments documented in the OEB's Conditions of Approval in the MAADs

[2] EB-2021-0002.

Decision[3], including the requirement to ensure any employment impacts resulting from the amalgamation will be managed on a roughly proportionate basis between the Municipality of Chatham-Kent and the City of Toronto, and that employment within Chatham-Kent would reflect a mixture of entry, middle, and senior level roles. The actual reductions that occurred in the deferred rebasing term were in fact roughly proportionate, with 18% employee reductions in Chatham-Kent and 15% reductions in Toronto, and the mix of employees across entry, middle and senior level roles remains highly consistent between the two municipalities. Enbridge Gas maintains a strong presence and high engagement with the Chatham-Kent community, regularly participating and investing in municipal meetings, events and opportunities.

16. Table 2 summarizes total compensation from 2013 to the 2024 Test Year. Overall compensation expense includes base pay, overtime pay, short-term incentive programs (STIP), long-term incentive programs (LTIP), employee life and health benefits, pension and other post-employment benefit costs (OPEBs).

[3] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018, p.15; EB-2017-0306, Exhibit J2.1, p1.

Table 2

Compensation

Line No.	Particulars ($ millions)	Utility	Salaries & Wages (1)	Total Benefits and Incentive Pay (2)	Total Compensation (3)	
			(a)	(b)	(c)	
1	2013 OEB-Approved	EGD/Union	377	171	548	
2	2013 Actual	EGD/Union	354	203	557	
3	2014 Actual	EGD/Union	370	190	560	
4	2015 Actual	EGD/Union	371	196	567	
5	2016 Actual	EGD/Union	370	190	560	
6	2017 Actual	EGD/Union	372	169	541	
7	2018 Actual	EGD/Union	300	144	444	
8	2019 Actual	EGI	286	158	444	
9	2020 Actual	EGI	275	148	423	
10	2021 Actual	EGI	279	143	422	
11	2022 Estimate	EGI	304	104	408	
12	2023 Bridge Year	EGI	310	112	422	/u
13	2024 Test Year	EGI	317	111	428	/u

Notes:

(1) Salaries and wages include overtime.

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

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

17. From 2013 to 2017, prior to the centralization brought about by the Enbridge and Spectra merger, salary and wages for Enbridge Gas were in line with FTE changes and merit increases. Starting in 2018, the amounts in Table 2 represent business unit FTE compensation as CF FTE compensation is allocated through CFCAM (please see Section 2 of this Exhibit). The reduction in total compensation was largely the result of centralization brought about by the Enbridge and Spectra

merger. The compensation for groups such as HR, TIS, and Finance were transferred to CF.

18. From 2019 to 2020, Enbridge Gas salary and wages declined as a result of a reduction in business unit FTEs due to restructuring in 2019, along with the VWO Program and salary rollback in 2020 which eliminated the merit increase slated for April 1 of that year. From 2020 to 2021, Enbridge Gas salary and wages rose as a result of an increase in FTEs to support integration as well as the reinstatement of the merit increase.

19. For the period from 2022 to 2024, salary and wages fluctuate as a result of merit and embedded productivity. Merit assumptions for 2023 and 2024 were informed by recent union settlement negotiations, rising inflation as well as the Company's annual review as provided in paragraph 28. Salaries and wages increase at a slower rate than expected FTE increases because of the Company's commitment to additional productivity savings embedded in the 2023 Bridge Year and 2024 Test Year O&M. As provided at Exhibit 4, Tab 4, Schedule 2, Section 1, although the Company has yet to conclusively identify additional productivity opportunities, the expectation is that active management of labour resources could result in lower FTEs than provided in Table 1 for 2023 and 2024. As such, preliminary gross O&M embedded productivity estimates of $5 million and $7 million have been included in the 2023 Bridge Year and 2024 Test Year, respectively.

20. For driver and variance explanations on benefits and incentive pay, please see Exhibit 4, Tab 4, Schedule 2, Section 8 for business unit benefit costs and Section 2.5 of this Exhibit for CF benefit costs.

21. Enbridge Gas provides competitive total compensation that includes base pay, incentive plans, benefits and pension for all employees. The goal of Enbridge Gas's total compensation program is to support the Company's recruitment, engagement, retention and retirement objectives of the workforce which enables the delivery of safe and reliable service for customers at a reasonable cost as confirmed by compensation and benefits benchmarking provided in Section 1.3.

1.1. Key Program Changes Since Last Rebasing Application

22. Beginning in 2017, following the merger of Enbridge and Spectra, Enbridge introduced common compensation, benefits and pension programs for employees for alignment and to streamline administration.

23. The use of compensation programs and structures targeted at market median has been an established practice that predates the last rebasing of both EGD and Union. The implementation of a new compensation structure with common incentive targets for Enbridge Gas supported integration of the amalgamated utility.

24. The new benefit and pension plans established common programs for all employees. These programs are designed to be competitive, modern, and highly valued. The new benefit plan provides Enbridge Gas employees with increased coverage focusing on mental health, an important element to supporting employee and family wellbeing.

25. The new pension plan eliminated the choice between defined contribution (DC) and defined benefit (DB) plans, which was previously available to new hires in both the EGD and Union pension plans. The new pension plan improved the long-term financial sustainability, particularly through the introduction of a 5-year DC

participation period for new hires, mandatory employee contributions and elimination of cost-of-living adjustments under the DB plan.

1.2. Program Descriptions

26. Enbridge Gas provides competitive and comprehensive compensation, pension and benefits to support workforce recruitment and retention objectives.

27. Compensation includes:
    a) Base pay;
    b) Short-term incentive pay; and
    c) Long-term incentive pay.

28. Base pay represents the fixed component of Enbridge Gas's compensation program. Base pay for non-union employees continues to be administered within a compensation structure with defined pay ranges (base pay minimums and maximums) to promote consistent and equitable pay administration across the organization. Base pay levels are reviewed annually following company guidelines which awards increases based on individual performance and pay range placement within an approved, market-aligned annual base salary (merit) budget. Individual performance is assessed by people leaders using a performance management process where role accountabilities and annual objectives are defined at the start of each year and evaluated against a five-point narrative rating scale at year-end. The base salary budget is established annually with consideration given to external compensation consultants' forecasts of salary increases, negotiated wage settlements and economic indicators such as consumer price index projections. Unionized employee wage increases are determined through negotiated collective agreements.

29. The STIP is an annual cash-based incentive plan that rewards enterprise, business unit and individual/team performance. The three components of STIP (enterprise-wide, business unit and individual) are weighted based on the level of your assigned role. This weighting reflects the degree of impact your role has towards the achievement of the goals defined at each level. Each year, goals are set across the enterprise and within each business unit to focus on strategic priorities and align with external stakeholder interests (e.g., customers, investors, regulators) to ensure safe, efficient, and effective processes and a skilled, knowledgeable workforce to carry out those strategies. All employees at all organization levels participate in STIP.

30. Employees at the manager level and higher also participate in the LTIP. As the name implies, LTIP is a variable pay plan focused on rewarding the achievement of Enbridge Gas's long-term goals or strategic objectives. These goals, such as growing the business, take several years to achieve. LTIP consists of stock option and share unit plans. LTIP provides participants the opportunity to benefit from the value that has been created as strategic objectives are achieved. It can take several years to realize this benefit, and the value is uncertain (i.e., pay at risk). LTIP aids in the attraction, motivation and retention of leadership talent who possess the competency, knowledge, experience and skills to operate the utility safely and is consistent with the expectations of all stakeholders including customers. Enbridge Gas's LTIP also includes limited participation below the manager level to support employee retention.

31. Designed to align with market median, STIP and LTIP targets are expressed as a percentage of each eligible employee's annual base pay. Targets vary by organization level, with executive and management employees having more pay at risk than front-line employees which is consistent with competitive market practices.

32. Variable incentive programs such as STIP and LTIP are common in the labour market and enable Enbridge Gas to compete for talent. Base pay rates would need to be higher if incentive pay was not included within Enbridge Gas's compensation strategy. The use of incentive pay is a reasonable, prudent and market prevalent approach to compensating employees as agreed by the OEB, citing:

> …use of incentive payments as a legitimate element of a total compensation package offered to attract and retain qualified managers and staff in a competitive market…
>
> The Board finds that the use of incentive payments is a reasonable element of Union's employee compensation and benefits ratepayers over the longer term by allowing Union to compete for high quality human resources, leading to a more efficient operation of the Utility.
>
> To the extent possible, the operations of the Utility should be consistent with good management in other sectors of the business community. As indicated elsewhere in this Decision, the Utility should be in a position to manage its business confidently and conventionally. Incentive programs are a common element of business management in all sectors of the economy, and have come to be regarded by employees, and prospective employees, as an essential element of compensation. Unless the incentive programs can be shown to be extravagant or otherwise objectionable, they should be supported as part of the revenue requirement. It would be perilous to create a situation in which the gas distribution utility, alone among business categories, could not effectively attract and keep quality employees through the offering of reasonable incentive programs. [4]

[4] RP-2003-0063, Decision with Reasons, April 8, 2004, lines 534-537.

33. The benefits program includes employee cost sharing and cost management features and has a strong focus on supporting and promoting employee and family wellbeing. The flexible benefits program includes:
    a) Medical benefits;
    b) Dental benefits;
    c) Life, accident and critical illness insurance;
    d) Short and long-term disability benefits; and
    e) Wellness incentives

34. The pension plan is a 5-year DC start, DB finish hybrid plan. New hires participate in the non-contributory DC provisions for their first 5 years and then automatically participate in the contributory DB provisions for the remainder of their career.

35. The other post-employment benefits (OPEB) plan provides eligible retirees with high-deductible medical coverage and a modest life insurance benefit.

36. Please see Exhibit 4, Tab 4, Schedule 2 for the historical actuals, 2022 Estimate, 2023 Bridge Year and 2024 Test Year of compensation and benefit programs, including pensions. The most recent actuarial valuation report is provided at Exhibit 4, Tab 4, Schedule 2, Attachment 1.

37. In addition to its own programs, Enbridge Gas is required to contribute to legislated government programs providing a range of employee benefits, including Employment Insurance, Canada Pension Plan, Workers' Safety and Insurance Benefits and the Employer Health Tax.

1.3. Compensation and Benefits Benchmarking

38. Enbridge Gas establishes market competitive total compensation programs by targeting the median level of compensation among peer companies. This is a long-established practice used by EGD and Union and now Enbridge Gas. Enbridge participates in compensation market surveys and pension and benefit benchmarking to enable competitive market analysis and the identification of prevailing compensation, benefits and pension practices and design trends. Targeting a median market position is a reasonable and prevalent approach required to attract and retain a workforce qualified to execute business objectives including providing safe and reliable service for customers. Therefore, targeting a median market position provides a reasonable value for cost for Enbridge Gas's customers.

39. Enbridge Gas engaged Mercer Canada Limited (Mercer) to conduct a competitive benchmarking review of compensation including base pay, STIP and LTIP (Mercer Report). The results indicate that compensation levels are positioned within the desired competitive zone defined as plus or minus ten percent of the median of the market peers - the positioning targeted by Enbridge Gas. The Mercer Report is provided at Attachment 1.

40. Enbridge Gas engaged Willis Towers Watson Canada Inc. (WTW) to conduct a competitive benchmarking review of the pension, savings and benefits programs (WTW Report). The results indicate that the employer-provided value of the pension and benefits programs continue to be positioned near the median of the peer group of companies, which is the target. The WTW Report is provided at Attachment 2.

2. Shared Services and Corporate Cost Allocation

41. Enbridge established CF in 2018 that provide shared services to its affiliates and allocates the CF costs using an internally developed Central Functions Cost Allocation Methodology (CFCAM). In addition to receiving these services, Enbridge Gas also provides shared services to its affiliates. The shared services provided by Enbridge Gas to its affiliates and the related charges are provided in Section 2.6 of this evidence. The remainder of Section 2 relates to the CFCAM and CF costs.

42. The purpose of this section is to describe the CFCAM, and to present the results of a third-party review of the CFCAM by Guidehouse Canada Ltd. (Guidehouse). Enbridge Gas retained Guidehouse to independently review both the CFCAM and the resulting CF costs allocated to Enbridge Gas using various methods of cost allocation and cost drivers described below. The report, Central Functions Cost Allocation Methodology Review (CFCAM Study), is provided at Attachment 3, and is further discussed within this section of evidence.

2.1. Background and History

43. The Filing Requirements for Natural Gas Rate Applications (Filing Requirements) defines shared services as the "concentration of a company's resources performing activities (typically spread across the organization) in order to service affiliates (including a parent company) with the objective of achieving lower costs and higher service levels" [5]. The Affiliate Relationships Code[6] (ARC) further defines shared services as "business functions that provide shared strategic management and policy support to the corporate group, of which the Utility is a member, relating to

[5] Filing Requirements For Natural Gas Rate Applications, February 16, 2017, p.29.
[6] Affiliate Relationships Code for Gas Utilities, November 25, 2010, p.4. https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Affiliate-Relationships-Code-for-Gas-Utilities-ARC-20101125.pdf

legal, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, investor relations, trustee or public affairs". The Filing Requirements also define corporate cost allocations as the "allocation of costs for corporate and miscellaneous shared services from the parent company to the utility (and vice versa)"[7]. Enbridge has established CFs in 2018 that provide shared services to its affiliate companies and allocates the CF costs amongst the service recipients using an internally developed CFCAM. EGD and Union have varying histories of corporate cost allocations for services received from their respective corporate parents prior to the merger of Enbridge and Spectra in 2017, discussed in further detail below.

EGD

44. Historically, Enbridge used an integrated approach to the management of its corporate and business unit segments by providing management services to its affiliates including EGD. Examples of management services provided and corporate cost allocations received included HR, Finance, TIS, Legal and Public Affairs and Communications (PAC), Safety & Reliability (S&R), depreciation and insurance[8]. A corporate Cost Allocation Methodology (CAM) was used to transfer costs to all affiliates, including EGD. A Regulatory Cost Allocation Methodology (RCAM) approved in EGD's 2013 Cost of Service proceeding[9] was implemented by EGD to meet regulatory requirements of the OEB and did not replace the existing CAM. The RCAM was independently reviewed by MNP LLP (MNP)[10] and concluded that the RCAM methodology continued to meet all regulatory requirements and

[7] Filing Requirements For Natural Gas Rate Applications, February 16, 2017, p.29.
[8] EB-2017-0306/EB-2017-0307, Exhibit C.CCC.15, for a complete listing of shared services received historically by EGD and Union from their respective corporate parents.
[9] EB-2011-0354, Settlement Agreement, October 3, 2012.
[10] EB-2011-0354, Exhibit D2, Tab 1, Schedule 1.

remained appropriate for EGD and for rate-making purposes[11]. EGD continued to apply the RCAM up to and including 2017.

Union

45. Union received corporate cost allocations for services, previously referred to as affiliate expenses, from its previous corporate parents and other affiliates including Duke Energy, Westcoast Energy Inc. and Spectra. Examples of services and corporate cost allocations received included HR, Finance, TIS, Supply Chain Management (SCM), S&R, Business Development, and Engineering and Construction, depreciation and insurance[12]. In Union's 2013 Cost of Service Application[13], Union provided a forecast of its affiliate expenses and demonstrated how these charges met the OEB's three-prong test[14] for recovery from customers. Union also filed service level agreements (SLAs)[15] to support the 2013 Test Year affiliate expenses in the absence of a cost allocation methodology. The OEB accepted Union's evidence that it had complied with the ARC and the three-prong test in the 2013 Cost of Service Settlement Agreement[16]. These charges were received up to and including 2017.

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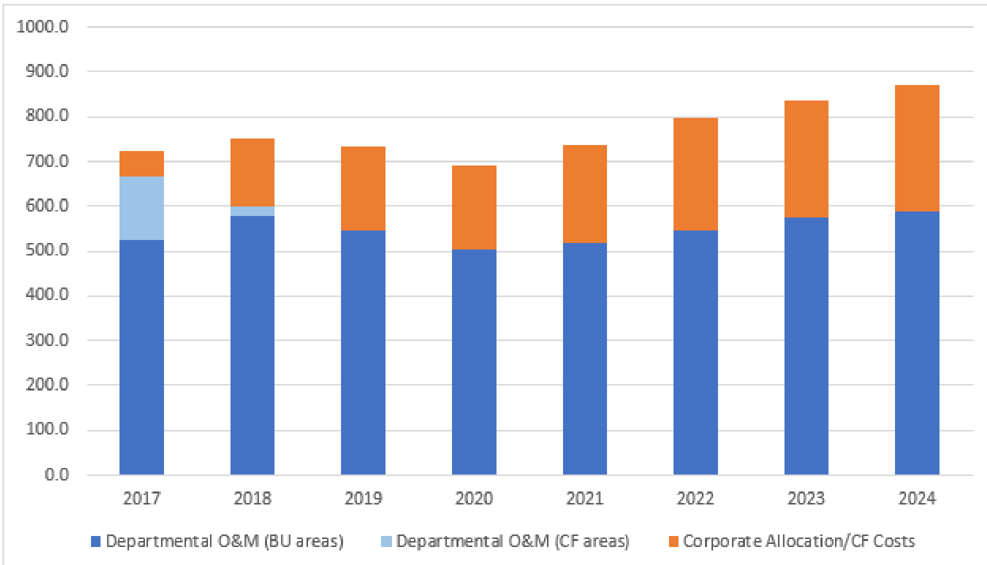
[11] EB-2011-0354 Exhibit D1, Tab 4, Schedule 2, p.4
[12] EB-2017-0306/EB-2017-0307, Exhibit C.CCC.15, for a complete listing of shared services received historically by EGD and Union from their respective corporate parents.
[13] EB-2011-0210.
[14] The three-prong test is a method defined in the E.B.R.O 493/494, OEB Decision with Reasons, March 20, 1997, to help with cost allocation decisions. The OEB's three-prong test sets the framework for determining if CF costs are in the public interest of Ontario customers based upon the prudence of the services received, the appropriateness of the allocation methodology, and the relative benefits of the service weighed against its costs.
[15] EB-2011-0210, August 2, 2012.
[16] EB-2011-0210, Settlement Agreement, June 28, 2012, Section 3.3, p.11.

2.2. CFCAM

Introduction

46. Enbridge implemented CFs beginning in 2018 and provides the associated services to affiliates, including Enbridge Gas, rather than the provision of those services by Enbridge Gas itself. Prior to the merger in 2017, these services were provided by utility-based employees and augmented by additional services provided by the respective corporate parent. The cost of services provided by the corporate parent were allocated to the business units using OEB-approved methodologies as provided in Section 2.1. Following centralization in 2018, services are provided by CFs which represent a combination of CF employees that 1) previously reported up through the organizational structure of Enbridge Gas and/or 2) CF employees of Enbridge. This has resulted in the shifting of costs from a combination of departmental O&M costs and corporate cost allocations received in 2017 to CF costs received from 2018 to 2024 as shown in Figure 1.

Figure 1: CF Cost Shift for Utility Net O&M (excl. Integration and DSM) /u



Notes:
(1) 2017 and 2018 reflects combined EGD and Union actuals.
(2) 2019 to 2024 represents net EGI actuals.
(3) Totals align to Exhibit 4, Tab 4, Schedule 2, Table 1, line 9.

47. Departmental O&M costs for Finance, Legal, TIS, PAC, HR, Benefits, SCM, S&R and Real Estate and Workplace Services (REWS) were embedded within EGD and Union's departmental O&M in 2017. The majority of departmental O&M in Figure 1 shifted to CF costs in 2018 upon the creation of CFs and implementation of the CFCAM. This resulted in the elimination of the CF area component within departmental O&M. Beginning in 2019, 100% of costs in Figure 1 represent CF costs and are reported as one line item, CF in Utility O&M. Please see Exhibit 4, Tab 4, Schedule 2, Table 1.

Current CFCAM

48. The costs of CFs, known as CF costs, are allocated among Enbridge affiliates based on the internally developed CFCAM as provided in Figure 2. The CFCAM can be found in the Intercorporate Services Agreement (ISA) provided at Attachment 4, Schedule 2. CF costs are collected in cost centres which are then grouped into service categories within a CF. Service category represent a grouping of CF cost centres into “like” services which form a total cost pool that is ultimately allocated to individual lines of business (LOBs)[17] as CF costs. These allocations are based on the principle of cost causation using cost drivers, where costs are driven by the activities required to provide the service.

Figure 2: CFCAM

Approach	Definition	Characteristics	Process
Directly Attributable Costs	Centralized Functions costs captured in Cost Centres, which are specifically attributable to a Segment. The costs will be 100% allocated to that Segment and subsequently allocated within the Segment using a cost driver.	• Cost recipient decided by **Centralized Functions** • Cost sent to **specific LOBs** in that Segment	Centralized Function → Service Category → Specific Segment → LOB 1 / LOB 2 / LOB 3
Directly Attributable Costs	The CF costs are attributable to multiple Segments. Such cost will be allocated in two steps: first the cost is assigned to individual Segments based on a driver, such as a time estimate, and subsequently allocated to LOBs within the Segments using another prescribed cost driver.	• Cost recipients decided by **Centralized Functions** • Cost is first sent to **specific Segments and then to LOBs** in such Segment	Centralized Function → Service Category → Segment 1 → LOB 1; Segment 2 → LOB 2 / LOB 3
Indirect Cost Allocation	Allocation of costs for services provided by Centralized Functions to the whole enterprise, and not specifically related to a single Segment.	• Costs are allocated to the **entire enterprise** using Cost Drivers	Centralized Function → Service Category → LOB 1 / LOB 2 / LOB 3
Direct Charge Cost	Certain costs residing in Cost Centres mapped directly to operating LOBs will be **excluded from the Allocable Cost Pool** and left as a direct charge to the Segment they roll up to.	• Costs are directed to the appropriate **Line of Business** • Affects **Legal, S&R,** and **Audit** costs that are under **“Direct Charge”**	Line of Business: Cost Centre

[17] LOBs represent subdivisions within a segment. Segments are Enbridge’s core businesses, comprised of: Liquids Pipelines, Gas Transmission & Midstream, Gas Distribution & Storage, Renewable Power Generation, Energy Services and Eliminations & Other. Enbridge Gas belongs to the Gas Distribution & Storage segment. Synonymous with business unit as described in the ISA.

Methods of Cost Allocation

49. There are three types of CF costs per the CFCAM, of which two are allocable:
    a) Directly attributable costs – costs that are specifically attributable to a segment, sub-segment or LOB due to the direct provision of service and clear ability to demonstrate cost causality;
    b) Indirect costs – allocated costs for services provided to the entire enterprise, and not solely to one segment; and
    c) Direct charge costs – Recorded directly in the LOB to which they pertain. Hence, no allocation is required.

Description of CFs

50. The following descriptions summarize the CFs and the services they provide:
    a) Aviation
        i. Provide air transportation service in response to company needs, and to conduct operations to the highest safety standards; and
        ii. Provide pipeline patrolling surveillance over pipelines.
    b) Corporate Development Office (CDO)[18]
        i. Develop and disseminate a strategic plan to position Enbridge Gas for sustainable growth and value creation;
        ii. Provide analytical decision support to investment decision makers.
        iii. Assess and create investment opportunities for growth; and
        iv. Integrate finance, communication, marketing and securities law compliance to enable the most effective communication between Enbridge, the financial community, and other constituencies.

[18] The CDO CF moved to the Finance CF in 2022.

c) Enterprise Asset and Work Management (EAWM)
   i. Manage the lifecycle of physical assets and equipment in order to maximize its lifetime, reduce costs, improve quality and efficiency, health of assets and environmental safety; and
   ii. Develop and implement advanced work management capabilities to deliver work in a more effective and efficient manner.

d) Executive
   i. Make major corporate decisions, manage operations and CFs, and overall resources;
   ii. Provide strategic and executive leadership over all Enbridge companies including Enbridge Gas;
   iii. Liaison between Enbridge and the investment community to improve access to capital markets and funding to support Enbridge Gas's operations and approved capital structure; and
   iv. Act as the main point of communication between the Board of Directors (BODs) and corporate operations.

e) Finance
   i. Trusted advisors driving value through disciplined financial management, insightful analysis, and rigorous compliance;
   ii. Provide information on actual and future financial performance, partner in decision making, and manage finance operations for the enterprise in addition to Enbridge Gas specifically. Includes financial and management reporting, and regulatory accounting;
   iii. Execute transactional accounting processes including invoice processing and management of capital asset reporting;
   iv. Execute capital, credit, tax, audit and risk assessment and control programs;

v. Maintain control environment and accounting policies, including enterprise-wide policies; and
vi. Support strategic and practical initiatives within the Finance function.

f) Real Estate and Workplace Services (REWS)
i. Provide a cost-effective workplace that enables the business to achieve its strategic objectives;
ii. Procurement of services and material;
iii. Manage real estate for the Enterprise;
iv. Develop and implement enterprise-wide standards; and
v. Execute and maintain agreements.

g) Human Resources (HR)
i. Provide advisory support for leader and employee relations and recruitment;
ii. Provide support for payroll, compensation, and benefits programs;
iii. Execution of talent management programs; and
iv. Overall oversight of the Enterprise HR program.

h) Legal
i. Provide comprehensive legal services to support corporate, commercial, litigation, regulatory and other business working with external counsel as necessary.

i) Public Affairs and Communications (PAC)
i. Engagement strategies that support the business objectives including enterprise communications, corporate social responsibility, community investment guidance and industry relations; and
ii. Strategic advocacy in support of projects, operations and public policy including public awareness outreach, stakeholder and Indigenous engagement and external affairs.

j) Safety and Reliability (S&R)
   i. Supports safety training, safety consulting services, regulation, and contractor programs; and
   ii. Provides support for risk, management, and governance within enterprise safety and operational reliability.
k) Supply Chain Management (SCM)
   i. Primary point of contact for internal customers;
   ii. Manage supply chain planning and supply chain execution;
   iii. Manage and negotiate spend and discounts for the enterprise; and
   iv. Define, recommend, and execute category strategies for key categories of direct and indirect goods and services.
l) Technology Information Systems (TIS)
   i. Manage the systems and applications that support the whole enterprise in addition to Enbridge Gas; and
   ii. Various TIS-related services including core infrastructure operations, operational technology, cyber security, IT service management and client services, network services, mobility, and technology direction and governance.
m) Benefits[19]
   i. Represents pension, long-term incentive, health, and other benefit costs.
n) Depreciation[20]
   i. Allocation of the cost of shared assets that provide benefits to the entire enterprise.

[19] Cost managed by CFs.
[20] Cost managed by CFs.

o) Insurance[21]

   i. Allocation of insurance premiums that are negotiated at an enterprise-wide level.

Cost Drivers

51. The CFCAM uses a combination of three types of cost drivers: consumption-based, static and a blended, multifactor driver (three-factor formula or 3FF). The 3FF is underpinned by the concept that the extent of utilization of a CF is driven by the size and contribution by a LOB. The 3FF is used to allocate costs that benefit the entire enterprise and is an appropriate driver to use as it creates a proxy for cost causation through representation of scale by number of people, capital and revenue of an organization and is discussed further in the CFCAM Study provided at Attachment 3 and the ISA provided at Attachment 4 and discussed in Section 2.3. Please see Attachment 5 for a list of CF costs and cost drivers for the 2022 Estimate and 2024 Test Year.

Benefits of Centralization

52. CFs provide all affiliates, including Enbridge Gas, with the following benefits:
   a) access to subject matter expertise;
   b) strategic oversight and corporate governance;
   c) strategic planning;
   d) sharing of best practices; and
   e) economies of scale.

53. Specific examples of benefits achieved through centralization are described below:

[21] Cost managed by CFs.

a) Access to Subject Matter Expertise

Each CF represents a pool of resources comprised of diverse teams with expert skills and experience across a large geographic region. Examples include specialized legal expertise (e.g. Indigenous and environmental law), Finance support for complex accounting issues and PAC services provided for emergency management. The absence of internal subject matter expertise would result in the procurement of these services externally.

b) Strategic Oversight and Corporate Governance

While Enbridge provides overall governance as Enbridge Gas's corporate parent, (Utility and Corporate structure is provided at Exhibit 1, Tab 3, Schedule 1, Section 18), Enbridge Gas maintains its own BODs and executive officers based in Ontario[22]. Enbridge Gas's BOD has delegated responsibility to several committees of Enbridge's BOD including audit finance & risk, governance and human resources and compensation. Enbridge Gas's reliance on Enbridge's committees is aligned with best practices and the OEB's guidance for utilities[23]. The strategic oversight provided by Enbridge enhances corporate governance while allowing Enbridge Gas to manage its operations and make key decisions.

c) Strategic Planning

CFs provide the vision, identify goals and objectives and guide the implementation of the long-term strategy for each CF. For example, Enbridge Gas continues to address the growing need for low-carbon alternatives and the transition required to integrate low-carbon alternatives into Enbridge

[22] All members of executive management reside in Ontario. One of three board members resides outside of Ontario.
[23] EB-2014-0255, Report of the OEB: Best Practices regarding Governance of OEB-Regulated Utilities, December 20, 2018.

Gas's strategic planning due to the ever-changing and evolving energy landscape. The CDO CF has supported Enbridge Gas in its strategic planning process and energy transition.

d) Sharing of Best Practices
The sharing of best practices allows the company to leverage the cumulative knowledge and experience of CFs which allows for more effective and efficient operations of CFs than if Enbridge Gas incurred CF type costs as a stand-alone utility in Ontario. An example can be found in S&R where industry-leading safety practices are shared to enhance Enbridge Gas's safety standards.

e) Economies of Scale
Examples of economies of scale include efficiencies through the use of shared enterprise assets and procurement discounts. Shared assets allows Enbridge to be more responsive to business needs and evolve and develop current and future services for which the costs are spread across the enterprise. Enbridge Gas also has access to higher volume discounts and enhanced purchasing powers in the market due to the consolidation of spending at Enbridge. Please see Exhibit 4, Tab 4, Schedule 1 for an overview of O&M costs, including CF costs, for EGD, Union and Enbridge Gas. Please see Section 2.5 and Exhibit 4, Tab 4, Schedule 2 Section 7 for a discussion of CF costs.

Enbridge Gas Validation of CF Services and CF Costs

54. Enbridge Gas has implemented validation processes including:

a) CF and service category review to identify changes (if applicable);
b) Confirmation of service provision and receipt with service providers and service recipients;

c) Cost driver review to ensure drivers remain appropriate; and
d) Analysis and review of variances to budget communicated by Enbridge.

55. Enbridge Gas and Enbridge ultimately attest through the completion and signing of the Schedule 3 to the ISA - Central Services Cost Allocation Methodology Confirmation Notice (Confirmation Notice) that the cost allocations determined in accordance with the CFCAM are acceptable. Please see Attachment 4 for Confirmation Notices from 2019 to 2022. There is also accountability by each of the CFs for CF costs. As articulated within Schedule 2 to the ISA, CF managers, are required to provide updated service descriptions of the services provided, identify and explain changes to cost drivers, and ensure all CF costs are reflective of the economic benefits received by respective Enbridge affiliates including Enbridge Gas.

56. Enbridge Gas's dedicated resources continue to perform its internal review of the CFCAM and CF costs to ensure services continue to be received and are required by the utility to ultimately conclude that CF costs are prudent.

57. The independent review performed by Guidehouse assessed CF costs using the OEB's three-prong test. The third prong requires a cost benefit analysis to be performed. Guidehouse performed a comparative analysis and found CF costs to be within range of various comparators selected. In addition to the cost benefit analysis performed by Guidehouse, Enbridge Gas has experienced the benefits of centralization noted in the examples described above. The combination of these factors indicates a balance between economy, efficiency and effectiveness of service levels and related CF costs.

2.3. ISA

58. The ISA between Enbridge and Enbridge Gas sets out the terms and conditions applicable to the provision of CF services from Enbridge to Enbridge Gas, in accordance with the ARC. The current ISA, provided at Attachment 4, is effective January 1, 2019, and automatically renews on an annual basis for a period of not more than 5 years (end of 2023). Schedules 1 and 2 were updated effective January 1, 2021, in accordance with an amending agreement provided at Attachment 4. During 2023, the parties plan to re-negotiate the ISA for a further period of not more than 5 years. The new ISA is expected to be substantially similar to the existing ISA, subject to date and process changes as required. The results of Guidehouse's review of the ISA are provided at Attachment 3.

2.4. CFCAM Study

59. Enbridge Gas retained Guidehouse to review and assess the CF cost allocations received through the CFCAM for alignment with the ARC and the OEB's three-prong test. The CFCAM Study is provided at Attachment 3.

60. Guidehouse performed a comprehensive evaluation of the CF cost allocations by first assessing the 2022 CF cost allocations budget (2022 budget) and associated CFCAM. Once Guidehouse provided its findings on the 2022 budget, Enbridge Gas applied the recommended adjustments, provided at Attachment 3, Table 6-3, to the CF cost allocations for the 2022 Estimate and 2024 Test Year. Guidehouse continued its review and relied on the analysis and findings derived from its evaluation of the 2022 budget to perform a reasonability assessment of the 2022 Estimate and 2024 Test Year CF cost allocations. The 2022 Estimate presents updated cost projections as compared to the 2022 budget and is the basis for the 2024 Test Year Forecast. The 2024 Test Year Forecast was derived by applying

inflationary increases and updates for known material items including TIS, depreciation, insurance, and pension costs included in benefits (Table 3, line 13) to the 2022 Estimate. For the development of the 2022 to 2024 pension forecast, Enbridge Gas engaged Mercer. Exhibit 4, Tab 4, Schedule 2, Attachment 1 contains Mercer's report which provides actuarial estimates of pension and OPEB plan accrual costs in accordance with US GAAP and the cash funding requirements. Where detailed cost inputs or drivers were not available, inflation adjustments were layered onto the 2022 Estimate. Inflation was projected at 2.4% for 2023 and 2.2% for 2024, as provided at Exhibit 3, Tab 2, Schedule 4. Guidehouse reviewed the inflationary increases applied to the 2022 Estimate to derive the 2024 Test Year CF cost allocations, for which Enbridge Gas is requesting recovery. The CF cost allocations for the 2023 Bridge Year do not form the basis for the amounts requested for recovery in 2024 and were therefore excluded from Guidehouse's review.

Guidehouse Conclusion, Adjustments and Observations

61. Guidehouse concluded that the 2022 Estimate and 2024 Test Year CF cost allocations pass the three-prong test. Guidehouse also concluded that 98.5% (or $318.8 million) of the allocated costs per the 2022 budget are reasonably incurred, established through cost drivers that observe key principles of cost allocations and offer benefits that equal or exceed costs for Enbridge Gas and its customers. Guidehouse also identified both proposed adjustments and observations in the CFCAM study regarding CFCAM costs allocated in the 2022 budget. The 2022 budget proposed adjustments, provided at Attachment 3, Table 6-3, were accepted by Enbridge Gas and manually reflected in the 2022 Estimate and 2024 Test Year, provided at Attachment 3, Table 9-1. As a result of these adjustments being reflected in these forecasts, no adjustments were proposed by Guidehouse to the

2022 Estimate and 2024 Test Year CF cost allocations. Observations, provided at Attachment 3, Section 8, are process-related and will be reviewed with Enbridge.

2.5. 2018 to 2024 CF costs breakdown and Variance Analysis

62. Table 3 outlines CF costs for 2018 to 2021 and the 2022 Estimate, 2023 Bridge Year and 2024 Test Year. Totals align with line 6 in Table 1 of Exhibit 4, Tab 4, Schedule 2.

Table 3
CF Costs

Line No.	CF ($ millions)	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Aviation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
2	CDO	1.5	1.5	1.5	1.6	2.4	2.4	2.5	
3	EAWM	0.0	0.0	0.2	0.6	1.8	1.8	1.9	
4	Executive	0.6	0.6	0.6	0.6	1.1	1.1	1.1	
5	Finance	30.1	25.2	25.0	28.4	35.1	35.9	36.7	
6	REWS	26.3	26.1	30.4	26.7	27.4	28.1	28.7	
7	HR	20.5	22.9	25.5	22.1	24.7	25.3	25.9	
8	Legal	10.4	13.7	11.0	11.0	14.7	15.0	15.3	
9	PAC	5.0	5.3	5.6	4.3	6.3	6.5	6.6	
10	S&R	4.8	5.7	8.1	6.8	7.2	7.4	7.5	
11	SCM	7.5	7.4	11.2	8.2	11.7	12.0	12.2	
12	TIS	59.4	70.2	66.0	75.0	108.3	125.4	139.7	
13	Benefits	34.1	27.2	26.6	57.1	60.3	64.8	66.1	/u
14	Depreciation	20.4	20.9	21.2	22.0	20.0	20.0	25.6	
15	Insurance	9.9	10.6	11.7	15.4	15.7	7.2	7.3	
16	CF costs	230.5	237.3	244.6	279.8	336.7	352.9	377.1	/u

Variance Analysis

63. Savings were delivered in CFs through organizational realignment following the merger of Enbridge and Spectra. Opportunities were realized with the centralization of CFs in 2018, the integration of EGD and Union, which allowed for the elimination of duplication as well as the VWO. Savings of approximately $16 million have been delivered through CFs as provided at Exhibit 1, Tab 9, Schedule 1.

64. The savings noted above have helped to mitigate some of the cost pressures affecting CF groups. The following paragraphs provide variance explanations for CF costs in Table 3 from 2018 to 2024. Total CF costs increased by approximately $147 million from 2018 to the 2024 Test Year, primarily due to the following: /u

    a) Approximately $31 million inflationary pressures throughout the deferred rebasing period;
    b) Approximately $66 million cost pressures related to TIS services provided;
    c) Approximately $45 million benefits cost increases for CF employees; and /u
    d) $5 million of other cost pressures net of cost savings in various CFs based on services provided.

65. A reporting alignment change related to benefits occurred in 2022 resulting in benefits costs being allocated to CF groups. $18 million of specific compensation-related benefits costs (i.e. STIP, Canada Pension Plan (CPP), Employment Insurance and various other benefits) shifted from benefits (line 13) to CF costs (lines 1 to 12). This change carries through to the 2024 Test Year.

66. The following paragraphs describe variances in cost for each CF from 2018 to the 2024 Test Year. Each function is impacted by inflationary cost pressures and the benefits alignment provided in paragraph 65 as well as savings driven by VWO.

The paragraphs below will address any further cost pressures related to the provision of services to Enbridge Gas for each CF.

67. Aviation costs that do not pertain to the monitoring of Enbridge Gas's pipeline systems and do not provide benefit to Enbridge Gas's customers and have been excluded from recovery.

68. CDO costs have remained consistent aside from increases due to inflation and benefits alignment.

69. EAWM is a new enterprise function providing services to Enbridge Gas as of 2020. EAWM provides expertise in the development and implementation of work management capabilities. EAWM costs have remained consistent aside from increases due to inflation and benefits alignment.

70. Executive costs have remained consistent aside from increases due to inflation and benefits alignment.

71. Finance costs have increased as a result of inflation and benefits alignment in addition to the creation of the Finance Sustained Business Organization (SBO) and Finance Strategic Solutions (FSS) groups, partially offset by synergies related to restructuring and VWO. Utility consolidation synergies are provided at Exhibit 1, Tab 9, Schedule 1. SBO and FSS provide new services to Enbridge Gas and were created to explore and drive out new productivity initiatives to identify potential cost savings, cost avoidance and revenue generation for Enbridge and its affiliates, including Enbridge Gas. SBO supports collaboration and connections across the company to maximize improvements and delivers a capability building program

focused on empowering individuals including Enbridge Gas employees with new mindsets and behaviours to drive innovation and unlock value for the organization (lean, agile, design thinking, etc.). FSS supports Enbridge Gas in enabling business process efficiencies and optimizations. This has included the deployment of 66 BOTs through Robotics Process Automation, eliminating 3,500+ productivity hours previously performed by employees and allowing for work redistribution to higher value activities.

72. REWS costs have increased as a result of inflation and benefits alignment. Offsetting these cost increases are synergies and productivity initiatives related to building maintenance efficiencies driven from a change in service provider for maintenance services for Enbridge Gas office space, alignment of service levels and migration to a hybrid work environment. Utility consolidation synergies are provided at Exhibit 1, Tab 9, Schedule 1.

73. HR costs have increased as a result of inflation and benefits alignment in addition to the expected increase in Enbridge Gas FTEs, as provided at Exhibit 4, Tab 4, Schedule 3, which will require additional HR support.

74. Legal costs have increased as a result of inflation and benefits alignment in addition to the centralization of legal services within the CF groups with corresponding decreases in CF costs for various CFs, including Finance.

75. PAC costs have remained fairly consistent aside from increases due to inflation and benefits alignment and the Indigenous Lifecycle Engagement and the Brand Reputation programs. The Indigenous Lifecycle Engagement Program is a relatively new area of focus which seeks to build positive long-term relationships with

Indigenous nations and groups, including those in Enbridge Gas's franchise area. The Brand Reputation program highlights the role Enbridge's assets, including those of Enbridge Gas, can play in reducing emissions over time in a cost effective and reliable manner.

76. S&R costs have increased as a result of inflation and benefits alignment in addition to new services provided to Enbridge Gas for occupational health and safety testing and equipment. Examples include testing for occupational hygiene including field testing for ammonia, lead, asbestos, mold, and air quality as examples.

77. SCM costs have increased as a result of inflation and benefits alignment in addition to the centralization of Enbridge Gas warehousing services from Distribution Operations to SCM. A corresponding decrease in Operations costs is provided at Exhibit 4, Tab 4, Schedule 2, paragraph 63.

78. TIS costs from 2018 to 2021 were relatively consistent considering the impact of inflation and reductions driven from efficiencies and synergies from restructuring and systems consolidation due to integration. From 2021 and beyond, increases in TIS costs were largely driven by improvements in technology system reliability, enhancements to Enbridge Gas business systems capability, and cyber security. Industry shifts to 'as a service' models have resulted in shifting costs from capital to O&M over time. This has resulted in a shift from traditional capital-intensive data center management and on-premise software licenses to O&M intensive infrastructure and software 'as a service' models. This is aligned to current industry trends and in most cases traditional capital models are no longer available. In addition, the elevated cyber threat in the oil and gas industry has driven increased cost to improve cyber security on information and operational technologies, including the protection of customer data.

79. Technology system reliability improvements delivered through the transition to 'as a service' models, have reduced the risk of significant critical system outages and enabled significant improvements in redundancy capabilities, planned outage window timeframes and service availability. Enbridge Gas business systems requiring software 'as a service' models have also increased O&M costs related to the implementation and sustainment of new business solutions. Specifically, in 2022, there is an increase in cost related to the sustainment of the Customer Information System due to migrating an additional 1.6 million residential customers onto a single system in 2021. The savings for this initiative are captured within the Customer Care function as provided at Exhibit 1, Tab 9, Schedule 1.

80. Shifts to 'as a service' models have also decreased our cyber risk by increasing our patching frequency and reducing the attack surface. The cyber security threat has increased significantly in the utility and energy industry. Geopolitical climate and cyber warfare tactics carried out by Nation State Actors target critical infrastructure systems with the goal of disruption in service delivery, espionage, political positioning, and revenue generation. Known large scale breaches of critical infrastructures over the last year are a testament to this threat as was seen in the Colonial Pipeline incident in May 2021. Incremental costs have been required to manage increased scope of monitoring and establishing security control on operational system assets, third-party vendors and meeting regulatory requirements in Canada through Bill C27 - Digital Charter Implementation Act 2022 and NIST - National institute of standards and technology cyber framework.

81. Benefits costs reduced from 2018 to 2020 is primarily attributable to the reduction in FTEs as a result of CF restructuring in 2018, the Enbridge Gas amalgamation restructuring in 2019 and VWO in 2020. In addition, there was year-over-year

fluctuation related to pension and OPEB resulting from actuarial valuations and changes in benefit expense for STIP, LTIP and health and other employee benefit expenses impacted by Enbridge Gas's performance metrics, insurance and medical industry trends and workforce levels. In 2021, CF benefits increased to $57.1 million due to a higher pension actuarial valuation, an increase in STIP based on the Company's performance and an increase in LTIP because of a higher share price at the end of the year. Also contributing to the increase, is a change in the tracking and reporting of BU and CF benefits from improvements in CFCAM. Through this reporting, it was identified that CF benefits represent a higher portion of the overall benefits than estimated in prior years. In 2022, CF benefits increased by $3.2 million to $60.3 million primarily due to higher LTIP based on a higher share price in early 2022 at the time of the forecast and higher health and other employee benefits costs. These increases were offset by a lower STIP forecast in 2022 compared to Enbridge Gas's performance in 2021, lower pension and OPEB costs based on actuarial valuations and the CFCAM benefit shift to functional areas provided in paragraph 65. CF benefits increased $4.5 million in 2023 due to higher /u
pension and OPEB costs based on actuarial valuations and inflation. In 2024, CF benefits are forecast to increase by $1.2 million due to inflation partially offset by lower pension and OPEB costs based on actuarial valuations.

82. Depreciation costs have remained consistent from 2018 to 2023. The increase in 2024 relates to the depreciation expense expected from the implementation of a new Enterprise Resource Planning (ERP) System at Enbridge Gas. The new ERP System is a transformational initiative that will integrate Enbridge systems, simplify, standardize and automate business processes, data and systems across Finance, SCM and EAWM enabling a more integrated way of working.

83. Insurance premiums have fluctuated from 2018 to 2024. Costs increased from 2018 to 2022 as a result of changing dynamics in the global insurance markets, which have led to increased difficulty for energy companies to access insurance at comparable premium rates. As provided at Exhibit 4, Tab 4, Schedule 2, Section 4.2, paragraphs 81-83, Enbridge has implemented an insurance strategy that focuses on insuring only low-probability, high-severity events. Under this approach, premiums are forecasted to decrease in 2023 and 2024, and relative to what they would have cost prior to the new insurance strategy.

2.6. Filing Requirements for Shared Services and Corporate Cost Allocations

ARC Self-certification for Shared Services

84. In order to satisfy the filing requirements for shared services and corporate cost allocations, Enbridge Gas has filed a self-certification of compliance with ARC. This self-certification is provided at Attachment 6.

Other Services Provided to Affiliate Entities

85. In addition to receiving shared services through CFs, Enbridge Gas performs services and incurs expenses on behalf of affiliates, which are subsequently reimbursed and recovered from affiliates. Expenses and recoveries for Business Development, Operations and Engineering are based on the cost of actual services provided (where applicable) or on a fully allocated cost basis. The total for the most recent actuals (2021) was $2.4 million. Reimbursements of $3 million in CF costs in 2021, including $2 million of charges to Enbridge, were recovered by Enbridge Gas in 2021 to ensure ARC compliance for shared services.

BOD Costs for Affiliates Included in O&M

86. Enbridge Gas receives allocations for costs related to Enbridge's BOD. As provided in Section 2.4.3.3 of the Filing Requirements[24], Table 4 presents the BOD-related costs for affiliates that are included in Enbridge Gas's O&M. Please see Section 2.2 of this evidence for a discussion on services provided by Enbridge's BOD.

Table 4
BOD Costs in O&M

Line No.	Particulars ($ millions)	EGD (1)	EGD/Union	EGI (2,3,4)
		(a)	(b)	(c)
1	2013	1.1	-	N/A
2	2014	1.2	-	N/A
3	2015	1.1	-	N/A
4	2016	1.0	-	N/A
5	2017	0.7	-	N/A
6	2018	N/A	0.4	N/A
7	2019	N/A	N/A	0.4
8	2020	N/A	N/A	0.4
9	2021	N/A	N/A	2.1
10	2022	N/A	N/A	1.4
11	2023	N/A	N/A	1.4
12	2024	N/A	N/A	1.4

Notes:
(1) Historical director fees were allocated through the RCAM process (2013 to 2017).
(2) The President & CEO of Enbridge Inc. does not receive director compensation.
(3) A portion of director compensation is paid through share-based awards. An increase to Enbridge's stock price resulted in higher fees in 2021.
(4) BOD costs forecasted to be allocated through the CFCAM for 2022 to 2024.

[24] Filing Requirements for Natural Gas Rate Applications, February 16, 2017.

3. Purchase of Non-Affiliate Services

87. This section provides information relating to procurement policies, processes, and procedures. SCM is a CF accountable for optimizing the procurement of goods and services for Enbridge. Execution of this mandate ensures that utility services are provided at the most prudent costs, under high standards of quality while reducing waste and maintaining governance of the overall logistical process. In keeping with that accountability, SCM has established policies and procedures which have been communicated through employee and vendor training. SCM also ensures that safeguards are in place to support compliance.

88. SCM's mandate involves 1) the procurement of materials and services through strategic sourcing and buying from qualified suppliers in a timely manner that meets business requirements, 2) applying a systematic approach to supplier management by maintaining strategic relationships with key suppliers that allows for a competitive advantage, compliance with contract terms, performance feedback and claims management, and 3) materials management that coordinates logistics, receiving and inspections along with ensuring adequate material storage, preservation, traceability and inventory levels.

89. As stipulated in the OEB Filing Requirements[25], the Enterprise Supply Chain Procurement Policy (SCM Policy) is provided at Attachment 7 and the associated policy relating to authorities and spending limits is provided at Attachment 8.

90. In addition, Attachment 9 contains the RFx (request for proposal/quote/ information) process and associated training materials to ensure the competitive processes are consistent and compliant with the overall policy. Finally, the Single

[25] Filing Requirements for Natural Gas Rate Applications, February 16, 2017.

Source Justification is provided at Attachments 10 and 11 which refers to situations where a competitive process cannot be followed.

91. Other controls in place include 1) Sarbanes-Oxley Act (SOX) compliance, 2) three-way match for payment of materials (purchase order, goods receipt, invoice), 3) an enterprise-wide contracts policy that standardizes and streamlines contracting across Enbridge, and 4) Gas Distribution and Storage Contract Owner Awareness Training. With the stringent controls and extensive training in place, Enbridge Gas is not aware of, nor does it expect any material transactions that are not compliant with the Enterprise Supply Chain Procurement Policy.

4. One-Time Costs

92. Section 2.4.3.3 of the OEB's Filing Requirements[26] outlines the requirement to identify one-time costs. One-time integration costs of $161 million were incurred over the deferred rebasing term were necessary to align and harmonize procedures, methods, policies as part of amalgamation. They also included one-time severance costs of $119.1 million associated with the elimination of roles resulting from the new amalgamated organization structure. Please see Exhibit 1, Tab 9, Schedule 1 for more details on integration-related costs.

93. No one-time costs are anticipated nor included in recoverable O&M amounts for the 2024 Test Year. Please see Exhibit 4, Tab 4, Schedule 2 for further information on 2024 Test Year costs.

[26] Filing Requirements for Natural Gas Rate Applications, February 16, 2017.

5. Low-Income Programs

94. This section addresses the various low-income programs within the DSM Energy Savings Program portfolio and the Low-Income Energy Assistance Program (LEAP).

5.1. Demand Side Management

95. Low-income programs were included in the approvals sought on the DSM Plan proceeding for 2022 to 2027[27] which is pending a decision from the OEB. These programs include home winterproofing and affordable housing multi-residential. as filed in the DSM Plan Application:

> the purpose of DSM programs tailored to lower income consumers is to recognize that these programs more adequately address the unique challenges involved in providing DSM programs for, and the special needs of, this customer segment. The Low-Income program is a set of program offerings designed for low-income residents of both single and multi-residential housing which may include resource acquisition or market transformation type offers. Hence, the distinctive features of these types of offerings result from additional guiding principles and design characteristics, as opposed to the nature of the program. This programming is critical in helping the most vulnerable customers manage their natural gas bills. [28]

96. Proposed low-income program budgets are $22.5 million, $23 million and $23.4 million for each of the 2022 Estimate, 2023 Bridge Year and 2024 Test Year, respectively.

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[27] EB-2021-0002.
[28] EB-2021-0002, Exhibit C, Tab 1, Schedule 1, p.17.

5.2. Low-Income Energy Assistance Program (LEAP)

97. The LEAP is an emergency bill assistance program supported by the OEB which provides grants to qualifying customers who are in arrears based on the number of home occupants and the total combined household income. The program provides emergency relief with financial grants of up to $1,000 per calendar year. This amount is applied directly to the outstanding balance on the customer’s gas bill and will vary based on account circumstances. LEAP is administered by a third-party, United Way Simcoe Muskoka, and is paid based on the number of successful applications plus a 15% administration fee. The program has been in place since 2015 and costs have averaged $2.5 million per year.

98. Since the inception of LEAP, there have been no changes to the program other than temporary support measures for Ontarians through the ongoing COVID-19 pandemic where, effective January 10, 2022, the OEB increased individual grants from $500 to $1,000. Please see Exhibit 9, Tab 2, Schedule 1, Section 6 for the impact these measures had on increased funding captured in the Impacts Arising from the COVID-19 Emergency Deferral Account.

99. Enbridge Gas is requesting approval for the inclusion of LEAP amounts within base rates, similar to the treatment previously followed by EGD. The LEAP forecast is $2.6 million annually for each of the 2022 Estimate, 2023 Bridge Year and 2024 Test Year.

6. Charitable and Political Donations

100. No charitable or political donations have been included in O&M for recovery.

Mercer

welcome to brighter

Compensation Benchmarking Review

Enbridge Gas Inc.

31 May 2022

A business of Marsh McLennan

Introduction and Executive Summary

Mercer Canada Limited ("Mercer") has been engaged by Enbridge Gas Inc. ("Enbridge Gas") to prepare an independent market-based assessment of the reasonableness of the total direct compensation levels for its non-union management, non-union positions below management and unionized positions.

This report is intended to assist in Enbridge Gas' regulatory proceedings before the Ontario Energy Board ("OEB").

Executive Summary

This review covers base salary, target total cash compensation (base salary + target short-term incentives) and target total direct compensation (total cash compensation + target long-term incentives). Mercer focuses on target total direct compensation instead of each individual compensation element since companies may place emphasis on different elements in order to accomplish different compensation objectives. The approach used in this review is consistent with Mercer's standard market benchmarking methodology.

In conducting the compensation analysis, Mercer worked with Enbridge Gas to identify benchmark positions that represent a statistically reliable sample of Enbridge Gas' functions and levels. Specifically, the review includes 354 non-union positions representing 82% of the non-union population, and 31 union positions representing 75% of the union population.

Mercer considers a job to be market competitive if it falls within +/-10% of the target market positioning (the 50th percentile for Enbridge Gas).

For non-union jobs, Enbridge Gas' base salary, target total cash compensation and target total direct compensation are each positioned at **1% below the market 50^{th} percentile**, which is within the competitive range. In general, Enbridge Gas is less competitive relative to the national energy sector, and more competitive relative to Ontario general industry.

For union jobs, Enbridge Gas is again positioned within the competitive range at **1% below the market 50^{th} percentile** relative to the job rate of Ontario collective agreements reviewed. Enbridge Gas is positioned at **4% above the market 50^{th} percentile** for both target total cash compensation and target total direct compensation.

Methodology

Mercer worked with Enbridge Gas to determine the appropriate markets for comparison to reflect the organizations Enbridge Gas competes with for talent (i.e., organizations that Enbridge Gas might reasonably recruit employees from or lose employees to).

Three comparator groups were identified for purposes of the compensation review. Comparators were selected by Mercer and confirmed by Enbridge Gas to be representative of the markets that Enbridge Gas competes with for talent:

Non-Union Positions

- **Ontario Comparator Group**
  - This comparator group reflects talent markets in Ontario that Enbridge would source talent from, and lose talent to, as most corporate positions do not require industry experience.
  - The data is sourced from the 2021 Mercer Benchmark Database and comprises of large (>$3 billion in revenue) private sector organizations, with significant Ontario presence. Only data for Ontario-based employees is considered from this robust sample of large, general industry companies
  - Where there is insufficient market data from the ideal comparator group, the scope was expanded until there is sufficient data to report in the following order: (1) All Ontario Public and Private Sector (25 positions), (2) All Ontario (2 positions), and (3) National All Industry (3 positions).
  - Market data is not reported for 75 positions that are energy-specific (e.g. Pipeline Scheduling).
- **Energy Comparator Group**
  - This group reflects companies most similar in nature to Enbridge Gas, that have similar compensation considerations in terms of administering pay and maintaining internal equity for a workforce across multiple provinces. This data set provides valuable perspective for positions that require energy industry experience.
  - The data is sourced from the 2021 Canadian Mercer Total Compensation Survey for the Energy Sector. In order to provide a robust data set from the database, the revenue scope was expanded relative to the Ontario comparator group and comprises mid-sized to large (>$1 billion in revenue) energy organizations
  - Where there is insufficient market data from the ideal comparator group, the scope was expanded to include all energy organizations (29 positions).
  - Market data is not reported for 16 positions as there is insufficient data to report.

Union Positions

- **Ontario Energy Comparator Group**
  - This group captures the Ontario market and collective bargaining job rates.
  - The data is sourced from 2021 collective agreements at energy organizations in Ontario with a unionized population. Enbridge Gas base salary is compared to the collective agreement job rate (i.e. structure maximum). Mercer has supplemented the job rate data with short- and long- term incentive data from our energy sector and Ontario general industry surveys to supplement the data available in the collective agreements. This allows us to provide a perspective of Enbridge Gas' competitiveness on target total cash and target total direct compensation.

Benchmark jobs were chosen by Mercer and verified by Enbridge Gas covering 354 non-union positions and 31 union positions across levels and functions.

For non-union positions, market comparisons are made to a blend of large, private sector general industry organizations in Ontario (67% weighting) and large, national energy sector organizations (33% weighting). The weightings were selected to recognize the local Ontario market where Enbridge Gas competes for talent for these roles while also considering the energy industry in which Enbridge Gas operates. The weightings are reversed for director level roles to reflect the fact that talent is sourced nationally and that energy sector experience is more important for these senior positions. For single incumbent director positions, a premium of 10% was applied to the market data to reflect the broader scope of responsibility for these positions.

Union positions were matched to Ontario collective agreements by title.

All compensation data is reflective of the most recently available data as of the completion of the analysis, and is presented effective for 2021.

Summary of Findings

Our commentary describes the competitiveness of Enbridge Gas' base salary, target total cash compensation and target total direct compensation relative to the 50th percentile of the respective market. Based on Mercer's compensation practices and policy research, the majority of organizations target compensation at the market 50th percentile, which balances fiduciary and cost considerations with the need to attract and retain talent. Mercer considers a job to be within the competitive range if they fall within 10% of the market 50th percentile.

The table below shows how Enbridge Gas' compensation compares to the market 50th percentile, for both union and non-union positions. For example, for both union and non-union positions in aggregate, Enbridge Gas' base salaries are 1% below the market 50th percentile.

	Base Salary	Target Total Cash	Target Total Direct
Non-Union Jobs	-1%	-1%	-1%
Union Jobs	-1% (1)	4%	4%

(1) Enbridge Gas base salary is compared to salary structure job rates (i.e. salary structure maximum) from Ontario collective agreements. Short- and long- term incentive data from our energy sector and Ontario general industry surveys have been used to supplement the data available in the collective agreements.

Non-Union Positions

The table shows the competitiveness of Enbridge Gas' non-union compensation, broken down by position type relative to the market 50th percentile. Management positions are those positions with direct reports (and matched to survey "Management" career stream) and non-Management roles are those positions without direct reports (and matched to survey "Professional" or "Support" career streams).

ENBRIDGE GAS	BASE SALARY		TARGET TOTAL CASH		TARGET TOTAL DIRECT	
POSITION TYPE	# Bench-marks	Avg. Market Variance	# Bench-marks	Avg. Market Variance	# Bench-marks	Avg. Market Variance
Management	*96*	5%	*89*	7%	*89*	9%
Non-Management	*258*	-4%	*236*	-3%	*236*	-5%
Overall	*354*	-1%	*325*	-1%	*325*	-1%

Overall, Enbridge Gas non-union positions are within the competitive range. Management positions are positioned more competitively than non-management, but are generally within the market competitive range.

Union Positions

The table shows the competitiveness of Enbridge Gas' union compensation relative to the market 50th percentile.

BASE SALARY(1)		TARGET TOTAL CASH		TARGET TOTAL DIRECT	
# Bench-marks	Avg. Market Variance	# Bench-marks	Avg. Market Variance	# Bench-marks	Avg. Market Variance
31	-1%	31	4%	31	4%

(1) Enbridge Gas base salary is compared to salary structure job rates (i.e. salary structure maximum) from Ontario collective agreements. Short- and long- term incentive data from our energy sector and Ontario general industry surveys have been used to supplement the data available in the collective agreements.

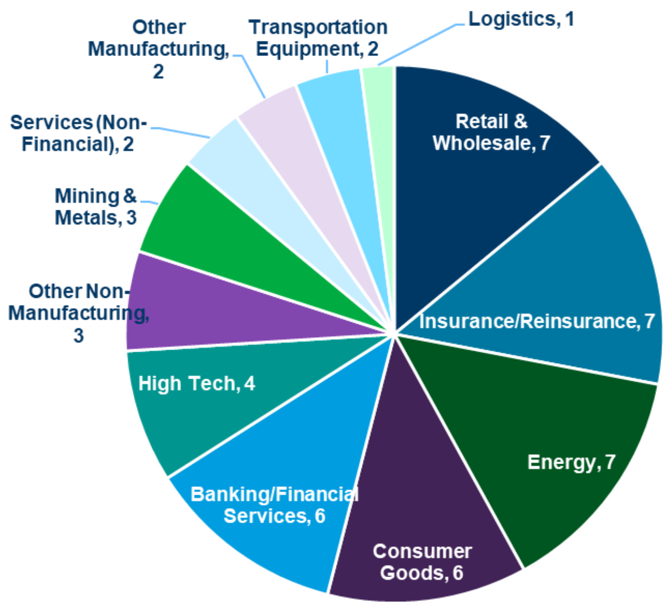
The majority of Enbridge Gas' union positions are within the market competitive range.

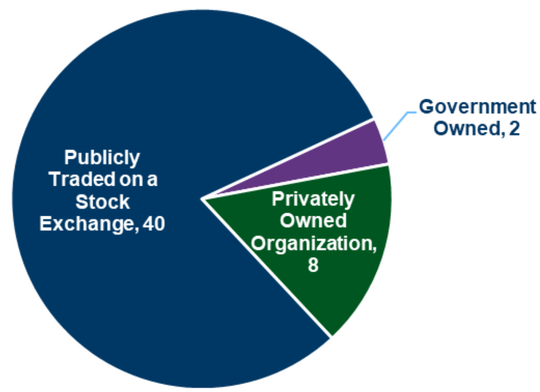
Appendix A

The following companies comprise the **Non-Union Ontario Comparator Group** (n=50).

Non-Union ONTARIO Comparator Group (Median Revenue = $7.27 Billion)	
1) Aecon Group, Inc	26) McDonald's Restaurants Canada Ltd
2) Agnico-Eagle Mines Limited	27) Metro-Richelieu, Inc
3) Agropur Cooperative	28) NOVA Chemicals Corporation
4) Assurant Canada	29) OMERS Administration Corporation
5) Bank of Montreal	30) Ontario Power Generation, Inc.
6) Bell Canada	31) OpenText
7) Canadian Imperial Bank of Commerce	32) Parkland Fuel Corporation
8) Canadian Pacific Railway Limited	33) Recipe Unlimited Corp
9) Canadian Tire Corporation, Limited	34) Richardson International
10) CGI, Inc	35) Royal Bank of Canada
11) General Motors of Canada	36) Samuel, Son & Co., Limited
12) Gordon Food Service Canada, Ltd.	37) Saputo, Inc.
13) Henkel Canada Corporation	38) Shaw Communications, Inc.
14) Hydro One, Inc.	39) Stantec, Inc.
15) IA Financial Services, Inc.	40) Sun Life Financial, Inc
16) Imperial Oil	41) Suncor Energy, Inc.
17) Intact Financial Corporation	42) Sunwing Travel Group, Inc.
18) John Deere Limited Canada	43) Sysco Canada, Inc.
19) Kinross Gold Corporation	44) TD Bank Group
20) Lactalis Canada	45) The Bank of Nova Scotia
21) Linamar Corporation Canada	46) The Co-operators Group Limited
22) Loblaw Companies Limited	47) The Great-West Life Assurance Co.
23) Manulife Financial Corp.	48) Toronto Hydro Corporation
24) Maple Leaf Foods, Inc.	49) Vale Canada Limited
25) Marsh Canada Limited	50) Wal-Mart Canada Corp.

The industry background and organizational format of the comparators is provided below:

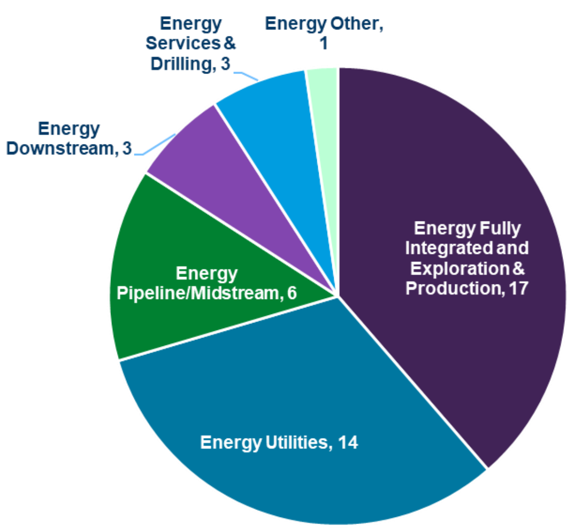


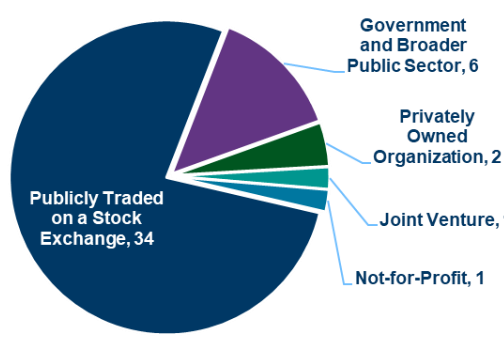


The following companies comprise the **Non-Union Energy Comparator Group** (n=44).

Non-Union ENERGY Comparator Group (Median Revenue = $3.94 Billion)	
1) Alberta Electric System Operator	23) Hydro-Québec
2) AltaGas, Ltd.	24) Imperial Oil
3) ARC Resources, Ltd.	25) Inter Pipeline, Ltd.
4) ATCO Ltd	26) Keyera Corp.
5) Baytex Energy Corp.	27) Liberty Utilities
6) BC Hydro Power & Authority	28) MEG Energy Corp
7) Cameco Corporation.	29) Nalcor Energy
8) Canadian Natural Resources, Ltd.	30) NOVA Chemicals Corporation
9) Capital Power Corporation	31) Nutrien, Ltd.
10) Cenovus Energy, Inc.	32) Ontario Power Generation, Inc.
11) Chevron Canada Resources	33) Ovintiv, Inc.
12) ConocoPhillips Canada	34) Parkland Fuel Corporation
13) Crescent Point Energy Corp.	35) Pembina Pipeline Corporation
14) Emera, Inc.	36) Secure Energy Services, Inc.
15) Enerflex, Ltd.	37) Shell Canada Limited
16) ENMAX Corporation	38) Suncor Energy, Inc.
17) EPCOR Utilities, Inc.	39) Syncrude Canada, Ltd..
18) ExxonMobil Canada	40) TC Energy
19) Fortis, Inc. - FortisBC, Inc.	41) Tervita Corporation
20) Gibson Energy	42) Toronto Hydro Corporation
21) Husky Energy, Inc	43) Tourmaline Oil Corp.
22) Hydro One, Inc.	44) Vermilion Energy, Inc.

The industry background and organizational format of the comparators is provided below:





The following companies comprise the **Union Comparator Group** (n=44).

Union Comparator Group			
	Union	**Unit**	**Organization**
1	Canadian Union of Public Employees	CUPE Local 87	Aitikokan Hydro Inc.
2		CUPE Local 1371	Cornwall Electric
3		CUPE Local 4705	Greater Sudbury Hydro Plus Inc.
4		CUPE Local 25	Lakefront Utility Services Inc.
5		CUPE Local 1813.10	Lakeland Power Distribution Ltd.
6		CUPE Local 72	North Bay Hydro Distribution Limited
7		CUPE Local 3839	Rideau St. Lawrence Utilities Inc.
8	International Brotherhood of Electrical Workers	Local 636, Unit 45	Brantford Power Inc.
9		Local 636	E.L.K. Energy Inc.
10		Local 1802	Electek Power Services Inc., Bluewater Power Dist. Corp
11		Local 636	Entegrus Powerlines Inc.
12		Local 636	Enwin Utilities Ltd
13		Local 636	EO Generation Limited Partnership
14		Local 636	Essex Powerlines Corporation
15		Local 636	Festival Hydro Inc.
16		Local 636	Hydro Ottawa
17		Local 636	Niagara Peninsula Energy Inc.
18		Local 636	Niagara-On-The-Lake Hydro Inc.
19		Local 636	Oshawa PUC Networks, Inc.
20		Local 636	Ottawa River Power
21		Local 636	Peterborough Utilities Services Inc
22		Local 636	Renfrew Hydro Inc.
23		Local 636	The Renfrew Power Generation Inc.
24		Local 636	Waterloo North Hydro Inc.
25		Local 636	Welland Hydro-Electric System Corp.
26	Power Workers' Union	CUPE Local 1000	Alectra Utilities Corporation
27		CUPE Local 1000	Algoma Power Inc.
28		CUPE Local 1000	Elexicon Energy Inc.
29		CUPE Local 1000	Erth Power Corporation
30		CUPE Local 1000	Great Lakes Power Limited
31		CUPE Local 1000	Grimsby Power Incorporated
32		CUPE Local 1000	Halton Hills Hydro Inc.
33		CUPE Local 1000	Hydro One Inc.
34		CUPE Local 1000	Kitchener-Wilmot Hydro Inc.
35		CUPE Local 1000	Kitchener-Wilmot Hydro Inc.
36		CUPE Local 1000	London Hydro Inc.

Union Comparator Group			
	Union	Unit	Organization
37		CUPE Local 1000	Newmarket-Tay Power Distribution Ltd.
38		CUPE Local 1000	Synergy North Corporation
39		CUPE Local 1000	Toronto Hydro
40		CUPE Local 1000	Westario Power Inc.
41	United Steelworkers	Local 2020-32	Air Liquide Canada Inc.
42		Local 2020	Reliance Comfort Limited Partnership
43		Local #16506	Revolution Environmental LP (Terrapure Environmental)
44		Local 6920-02	Triple M Metal LP

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ENBRIDGE GAS INC.

PENSION, SAVINGS AND BENEFITS PROGRAMS BENCHMARKING

September 23, 2022

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Introduction

Enbridge Gas Inc. ("Enbridge") engaged Towers Watson Canada Inc. ("WTW") to conduct a competitive benchmarking review of the pension, savings and benefits programs offered to Enbridge's unionized and non-unionized employees. The purpose of this review is to:

- Provide an independent, market-based assessment of the market positioning of Enbridge's pension, benefit and savings programs relative to the peer organizations that Enbridge competes with for employees; and
- For filing with the Ontario Energy Board, in connection with Enbridge's rate-setting application.

For purposes of this review, we have included the following benefits programs (collectively the "benefit programs"):

- Pension (including Defined Benefit and Defined Contribution Plans)
- Savings (including Group RRSP, DPSP, etc.)
- Stock Purchase
- Health Care (active and retiree)
- Dental Care (active)
- Short-Term Disability
- Long-Term Disability
- Death Benefits (active)
- Flexible Benefits (other than Pension)

The review was conducted using WTW's proprietary BenVal method for determining the value of benefit programs by applying a consistent set of actuarial methods and assumptions to a common employee population. BenVal results provide a quantitative evaluation of each organization's benefit provisions and overall benefit program, and facilitate a comparison of these benefit values against peer organizations.

Methodology

BENVAL

BenVal is WTW's benchmarking method frequently used to assist clients in determining the market competitiveness of their benefit programs.

WTW's proprietary BenVal method performs benchmarking comparisons by determining and comparing values for benefit programs provided by organizations that participate in WTW's Benefits Data Source (BDS). This method determines values using a consistent set of actuarial methods and assumptions applied to a common employee population.

BenVal is focused on employer-sponsored benefit programs only. Benefit programs are those that are currently in force and which are applicable for newly hired regular full-time salaried employees. Closed or grandfathered peer plans are not included. The amounts determined through BenVal represent the average value, per employee, for the valuation year.

BenVal establishes a controlled environment where differences in value among employer plans are exclusively a function of the differences in plan provisions. A BenVal analysis is not intended to compare actual benefit costs. Each organization's actual benefits costs are affected by its benefit program design, but also by other factors which are not captured in a BenVal analysis such as funding decisions, plan experience and demographics. Each plan is valued under the same actuarial valuation method using a consistent set of actuarial assumptions and employee population.

The results described in the report are based on a 2021 BenVal analysis that reflected the most recent data and benefit program information in WTW's BDS – Canada database as at May 2021. The program description for each participant was obtained within two years of the analysis. BDS maintains data in 125 countries for more than 16,000 participants.

Actuarial Cost Method

The actuarial cost methods used to calculate the values for the benefit programs are the Projected Unit Credit with service prorate method and the Term Cost method – two commonly accepted actuarial cost methods. These methods take into consideration various actuarial assumptions including an employee's current salary, the probable number of years they have until they retire or terminate employment and will receive preretirement benefits, the likelihood of being disabled, the annual rate at which the employee's salary increases, the annual pension and benefits they will receive when they retire, and the probable number of the years the individual will live to continue receiving their annual pension. Any inflation adjustments are also valued.

To develop such values, benefits are initially analyzed in terms of when they become payable. Those benefits payable in the future — defined benefit pension plans (all ancillary benefits included) and postretirement health care benefits — are valued in terms of anticipated prospective benefit payments being allocated over the employee's entire working history (Projected Unit Credit with service prorate method). Those benefits potentially payable over the current year — defined contribution pension plans, savings plans, stock purchase plans, preretirement death, health care and dental care benefits, and disability benefits — are valued based on the probabilities of the various events occurring within the year, multiplied by the value of the benefit (Term Cost method). No other benefits are valued.

The employer-provided value is determined by deducting employee contributions from the total value.

Additional information on the BenVal methodology for the different benefit programs, the assumptions and the employee population are detailed below.

Defined Benefit Pension Plans

Defined benefit pension plans provide a specified, pre-established benefit for employees at retirement or termination of employment. Typically, the benefit is calculated through a plan formula that considers factors such as age, length of employment and salary history.

The following elements are considered in determining comparative values for defined benefit pension plans: normal and early retirement benefits and postretirement death benefits, termination benefits, postretirement pension adjustments and employee contributions. Postretirement pension adjustments are valued according to plan provisions or the organization's policy when not stated in plan provisions.

When a plan offers the possibility to switch between a defined contribution pension plan and a defined benefit pension plan, employees are deemed to participate in the defined contribution pension plan if they are younger than age 46 as of the valuation date. If they are age 46 or older as of the valuation date, they are deemed to participate in the defined benefit pension plan. For the purpose of valuing the defined benefit plan, the Projected Unit Credit benefit is prorated over credited service after age 46. If the decision made at plan entry is irrevocable, employees who join the plan prior to age 36 are deemed to participate in the defined contribution pension plan while the others are deemed to participate in the defined benefit pension plan.

Defined Contribution Pension Plans, Savings Plans and Stock Purchase Plans

Defined contribution pension plans and savings plans are programs in which the employee and/or the employer contribute to the employee's individual account under the plan. The amount in the account at distribution includes the contributions and investment gains or losses, minus any investment and administrative fees. Generally, the contributions and earnings are not taxed until distribution. Stock purchase plans allow employees to acquire company stock, usually at a discounted price.

Plans are valued by determining employee and employer contributions made during the year of valuation (Term Cost method). Where employee contributions are not fixed, employees are deemed to contribute in such a way that reflects their savings opportunity and ability to contribute. Accordingly, they will be assumed to contribute differently depending on available income, on the level of contributions permitted in the plan and on the level of employer match.

Contribution levels to profit sharing plans are determined by averaging the last five years' actual contributions to the plan.

Health Care and Dental Care Plans

Health care values are generated for preretirement and postretirement (using the Projected Unit Credit with service prorate method) coverage. Postretirement values and retiree contributions are increased to reflect future inflation. However, deductibles under postretirement health care plans are assumed to remain at the current level in the future. Dental care values are generated for preretirement coverage only.

Values are determined using recent claims experience for large organizations taking into account plan deductibles, coinsurance and maximums as well as eligibility requirements.

In line with general market practice, health care plans (including drug plans) are generally assumed to be second payer to any provincial health care plans when applicable. It is also assumed that the current practice with respect to government programs having an impact on our calculations would remain unchanged.

Any amounts allocated to the Health/Dental Care Spending Account are included in the health care plan value.

Disability Plans

Short-term disability benefits include salary continuance and sickness plans.

Values are determined according to specific plan provisions including waiting periods, durations, benefit amounts and indexation.

Death Benefit Plans

Values are calculated for preretirement group life insurance and accidental death and dismemberment benefits. Optional insurance benefits are not valued.

Flexible Benefits (other than Pension)

Flexible benefits (other than pension) are arrangements which allow employees to pay for many out-of-pocket medical, dental, insurance and disability expenses with tax-free dollars.

The value determined for these benefits is based on the highest enrolled option for each plan.

When not determined by the plan design, flexible benefit credits are allocated in the following order: health care benefits, dental care benefits, life insurance benefits and disability benefits. Remaining flexible credits, if any, are included in the value of the residual flex credits.

Any postretirement Health/Dental Care Spending Account is assumed to remain at the current level unless stated otherwise by participants, in which case the annual increase assumption provided by each participant is applied.

Peer Group

The benchmarking review was conducted by comparing the pension, savings and benefits programs of Enbridge against a peer group of 14 organizations.

Enbridge selected the peer group for the purposes of this review. The methodology for selecting the 14 peer organizations included in the peer group was determined as follows:

- Include all large organizations in the Ontario utilities industry.
- Include peer organizations in the oil and gas industry, which have a significant number of employees in Ontario.
- Include large organizations that operate outside of the utilities and oil and gas industries, representative of the modest proportion of office/professional workers where Enbridge competes for talent. Organizations in this criterion operate in a variety of industries, including the financial services and telecommunications industries.
- Finally, certain organizations selected under this methodology are excluded if no pension and benefit program information is available in the WTW BDS database.

The peer group selected for this review is consistent with the peer group that Enbridge uses for internal company benchmarking reviews and reporting.

Enbridge's foregoing methodology is consistent with the methodology used by other WTW clients for selecting peer organizations and appears reasonable for purposes of this analysis.

Organizations	
Bell Canada	Labatt Brewing Company Limited
Bruce Power	Ontario Power Generation
Canadian Imperial Bank of Commerce	Rogers Communications Canada Inc.
Enercare Home and Commercial Services	Sun Life Financial
Husky Energy	Suncor Energy
Hydro One	TC Energy
Imperial Oil	Toronto Hydro Electric Systems

The BenVal results provided in this report are based on the benefits data provided to WTW by participating organizations in the BDS database. Participants are responsible for providing and maintaining accurate benefits information on their current in force programs that are applicable to newly hired full-time salaried employee. WTW has relied on these data after reviewing them and assessing their reasonableness. However, WTW has not independently audited these data.

Actuarial Assumptions

The assumptions used and summarized below were selected by WTW and are applied to the actuarial cost methods described above. These assumptions represent our standard BenVal assumptions that have been consistently applied to determine the value for Enbridge and each organization in the peer group.

Economic Assumptions	
Discount rate:	5.0% per year
Salary escalation:	3.5% per year
Escalation of Income Tax Act maximum pension limit:	3.0% per year
Escalation of Maximum Pensionable Earning (MPE):	3.0% per year
Inflation (CPI increase):	2.0% per year
Increase in health plan values and retiree contributions for postretirement benefits valuation:	4.5% per year
Postretirement Health/Dental Care Spending Account:	Not trended

Demographic Assumptions	
Mortality:	Combined Private and Public Sector Canadian Pensioners' Mortality Table (CPM2014) projected to 2030 using CPM-B
Termination of employment:	Age-related rates (see Table 1)
Disability:	
■ Pension	None
■ STD	Developed based on (1) large company experience, (2) Society of Actuaries STD experience data, (3) 1987 Commissioner's Disability Table
■ LTD	1987 Commissioner's Group Disability Table, with six-month elimination period; adjusted where more restrictive LTD requirements apply
■ Termination of disability	1987 Commissioner's Group Disability Table (adjusted + 11% to remove insurer margin)
Retirement:	Incidence varies by the age at which retirement benefits are unreduced. (see Table 2 for illustrative probabilities). Earliest age of unreduced benefits is assumed to be 62 for the purpose of valuing postretirement health care plans
Employee/Family status:	Employees are assumed to be married. Female spouses are assumed to be three years younger than male spouses. Employees are assumed to elect family coverage

Table 1 – Termination of employment factors

Age at Termination	Rate
20 - 24	15% each year
25 - 30	10% each year
31 - 45	Starts at 9.5% at age 31 and reduces by 0.5% at each age
46 - 54	2% each year
55 +	0% each year

Table 2 – Illustrative probabilities of retirement

	Earliest Age of Unreduced Benefit			
Age at Retirement	55	60	62	65
50	2%	2%	2%	2%
55	15%	4%	4%	4%
60	15%	15%	10%	10%
62	30%	30%	30%	20%
65	100%	100%	100%	100%

For example, under a plan that provides an unreduced benefit at age 62, 30% of active employees who reach that age (that have not terminated for any reason previously) will retire at age 62.

Population Charts

The population data used and summarized below represents WTW's standard BenVal data which has been consistently used to determine the values for Enbridge and each organization in the peer group.

Using standard population data for BenVal along with the same assumptions, establishes a controlled environment where differences in value among employer benefit programs are exclusively a function of the differences in plan provisions.

Age, Service and Base Pay

		Completed Years of Service							
Age (% female)		Less than 1	1	2 – 4	5 – 9	10 – 19	20 – 29	30 +	Total
0 – 19 (0%)	Number	1							1
	Avg Base Pay	$34,534							$34,534
20 – 24 (39%)	Number	10	8						18
	Avg Base Pay	$47,092	$47,092						$47,092
25 – 29 (44%)	Number	22	18	40	8				88
	Avg Base Pay	$57,556	$57,556	$57,556	$59,650				$57,747
30 – 34 (44%)	Number	23	18	42	37	15			135
	Avg Base Pay	$63,835	$63,835	$63,835	$68,021	$66,975			$65,331
35 – 39 (42%)	Number	22	17	41	50	50			180
	Avg Base Pay	$66,975	$66,975	$65,928	$65,928	$69,068			$67,027
40 – 44 (44%)	Number	18	15	33	38	61	27		192
	Avg Base Pay	$70,114	$70,114	$70,114	$71,161	$81,625	$80,579		$75,450
45 – 49 (44%)	Number	11	9	21	30	45	42		158
	Avg Base Pay	$69,068	$69,068	$69,068	$73,254	$78,486	$86,858		$77,274
50 – 54 (43%)	Number	8	6	15	17	32	38	16	132
	Avg Base Pay	$76,393	$76,393	$76,393	$70,114	$77,440	$87,905	$89,997	$80,801
55 – 59 (43%)	Number	3	2	5	10	19	17	14	70
	Avg Base Pay	$65,929	$65,929	$65,929	$70,114	$73,254	$84,765	$104,648	$80,833
60 + (38%)	Number	2	2	2	3	7	6	4	26
	Avg Base Pay	$75,347	$75,347	$75,347	$59,649	$71,161	$78,486	$94,184	$76,031
Total	Number	120	95	199	193	229	130	34	1,000
	Avg Base Pay	$64,123	$64,364	$65,713	$68,726	$75,708	$85,200	$96,522	$71,845

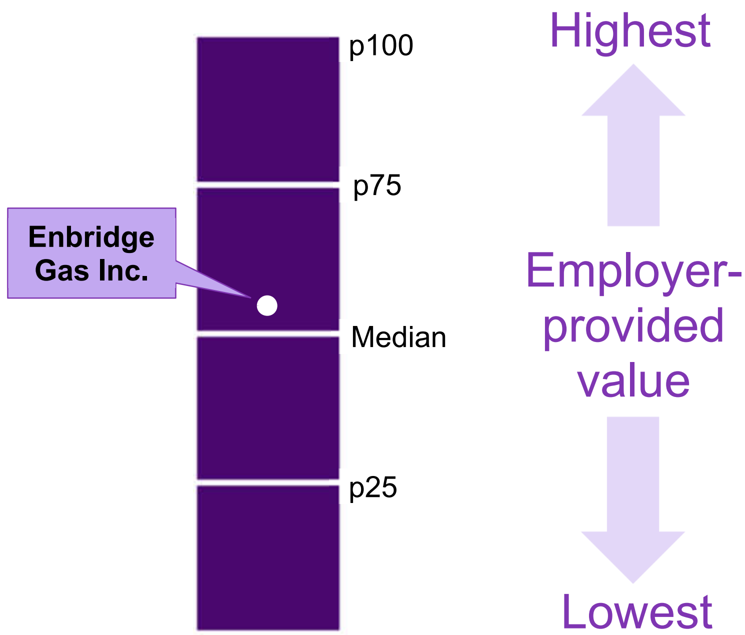
Average Age: 41.7 years Average Service: 9.9 years

Target Bonus

Base Pay	Bonus as a % of Base Pay
Less than $47,500	0%
$47,500 – $62,499	6%
$62,500 – $77,499	8%
$77,500 – $89,999	10%
$90,000 – $99,999	13%
$100,000 and more	16%

Benchmarking Results

The employer-provided value of Enbridge combined pension, savings and benefits programs is competitive and ranks them 6.3% above the peer group median.



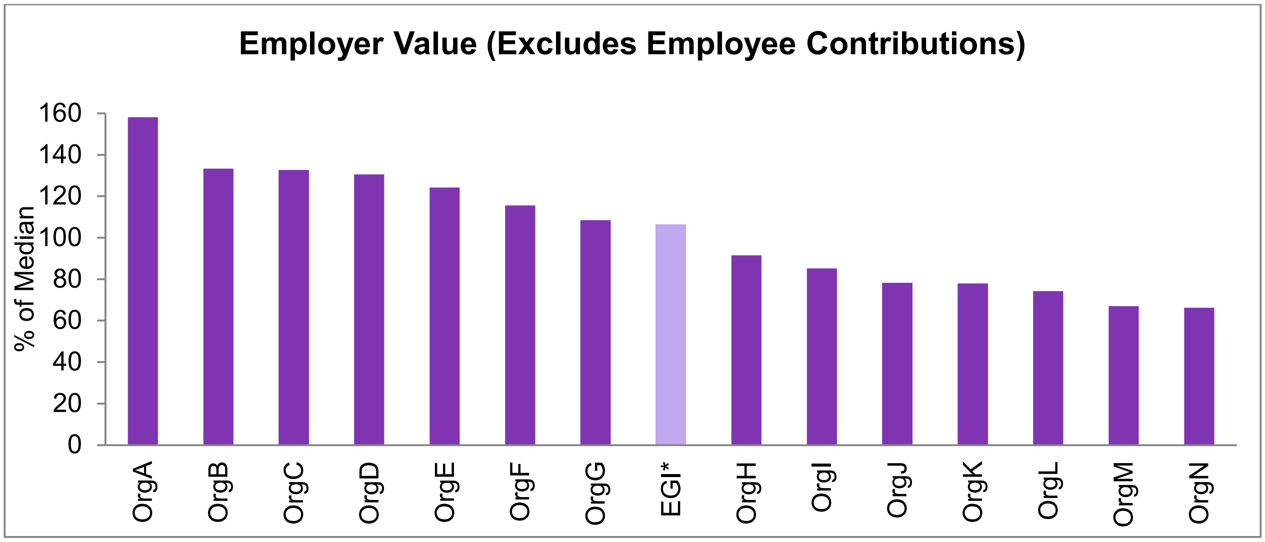
Enbridge's relative ranking to the peer group median is generally consistent with the 2016 benchmarking analysis.

Interpretation of the statistical terminology:

- Enbridge's relative ranking to the peer group is presented as percentiles.
- Peer organizations are ordered based on their calculated value from lowest to highest. The various percentiles are determined as follows:
  - P25 (25th percentile): Indicates the value that separates the peer group in such a way that 75% of the reported peers are above and 25% are below.
  - Median (50th percentile): Indicates the value that separates the peer group in such a way that 50% of the reported peers are above and 50% are below.
  - P75 (75th percentile): Indicates the value that separates the peer group in such a way that 25% of the reported peers are above and 75% are below
  - P100 (100th percentile): Indicates the highest value in the ordered peer group

Detailed Benchmarking Results

- Enbridge's relative ranking to the peer group is positioned at 106.3% of the median.
- The organization within the peer group providing the highest employer-provided value is positioned at 158% of the median.
- The organization within the peer group providing the lowest employer-provided value is positioned at 66% of the median.



Note:

* In order to understand how Enbridge's benefit programs rank relative to the peer group, Enbridge's benefit programs are excluded from the calculation to determine the relevant percentiles.

* The Enbridge benefit programs benchmarked represent the plans currently in force for the majority of employees, including future new hires (both non-union and union). Enbridge's closed or grandfathered programs are not included. The pension plan benchmarked reflects the new hybrid pension plan introduced in 2018 which is a 5-year defined contribution start, defined benefit finish.

Actuarial Opinion

In our opinion, for the purposes of the competitive benchmarking review of the pension, savings, and benefit programs offered to Enbridge's unionized and non-unionized employees:

- the standard population data on which the BenVal analysis is based is appropriate,
- the assumptions are appropriate,
- the methods employed in the BenVal analysis are appropriate, and
- the results of this report, which will be used as expert evidence to assist the Ontario Energy Board, are fair and objective and have been prepared in accordance with Rule 13A of the Ontario Energy Board's Rules of Practice and Procedure.

This report has been prepared, and our opinion has been given, in accordance with accepted actuarial practice in Canada.

Towers Watson Canada Inc.

W.R. Colbert

Randy Colbert
Fellow of the Canadian Institute of Actuaries

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September 23, 2022

Appendix A: Disclaimers and Data Use Restrictions

The results presented in this report have been developed using a particular set of actuarial assumptions. Other results could have been developed by selecting different actuarial assumptions. The results presented in this report are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events.

The results provided in this report are based on the benefits data and information provided to us by participating organizations. Participants are responsible for providing and maintaining accurate benefits information. Towers Watson Canada Inc. ("WTW") has relied on these data after verifying them and assessing their reasonableness. However, WTW has not independently audited these data. WTW is not responsible for any errors that may occur in the results if any portion of this information is later deemed to be erroneous.

The information contained in this report was prepared for Enbridge Gas Inc., for its internal use and for filing with the Ontario Energy Board, in connection with its rate-setting application. This report is not intended, nor necessarily suitable, for other parties or for other purposes. Further distribution of all or part of this report to other parties (except where such distribution is required by applicable legislation) or other use of this report is expressly prohibited without WTW's prior written consent. WTW is available to provide additional information with respect to this report to the above-mentioned intended users upon request.

All proprietary rights (including without limitation all trade secrets, trademarks, trade names and copyrights) to this report (including without limitation all related specifications, techniques, methods and algorithms contained in it) belong exclusively to WTW.

Certain additional restrictions apply to the Recipient's use and disclosure of the data. The Recipient may disclose to any of its employees the relative value position of the Recipient's benefit plans as compared to the aggregate results for other companies whose information is included in the study. However, the Recipient may not disclose plan specifics or other details with respect to those other companies except to the Recipient's human resources and other senior management.

Enbridge Gas Inc.

Central Functions Cost Allocation Methodology Review

Submitted by:

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October 17th, 2022

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Disclaimers

This deliverable was prepared by Guidehouse Canada Ltd. ("Guidehouse") for the use of, and pursuant to a client relationship exclusively with Enbridge Gas Inc ("Client"). The work presented in this deliverable represents Guidehouse's professional judgement based on the information available at the time this report was prepared. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

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1. Glossary and Definitions

Term	Definition
Affiliate	Has the same meaning as in the *Business Corporations Act* (Ontario).
Affiliate Relationships Code for Gas Utilities (ARC)[1]	Sets out the standards and conditions for the interaction between gas distributors, transmitters and storage companies and their respective affiliated companies.
Central Function (CF)	Business function managed and operated centrally, which provides services to Segments. Central Functions are synonymous with Central Services as described in the Intercorporate Services Agreement.
Central Functions Cost Allocation Methodology (CFCAM)	The methodology pursuant to which Enbridge Inc. (EI) identifies and allocates the costs of the services received and provided by EI and its Affiliates, including Enbridge Gas Inc (EGI).
Cost Centre	Department or unit to which costs are charged for accounting purposes.
Cost Driver	An activity related to the cost incurred to provide a service. Indicator of the level of services received. Drivers can be consumption-based (variable) or static (fixed).
Cost Pool	Costs of all Central Function Cost Centres.
Directly Attributable Costs	Costs that are specifically attributable to a Segment, Sub-segment, LOB or LOBs due to the direct provision of service and clear cost causality. Costs can be directly allocated back to the originating Segment/LOB/LOBs or to other Segments/LOBs to which services are provided.
Direct Charge Costs	Costs recorded directly in the LOB to which they pertain. Hence, no allocation is required. Legal, Public Affairs and Communications Audit and Safety & Reliability costs include Direct Charge Costs.
EGI	Enbridge Gas Inc.
EI	Enbridge Inc. or Enbridge
Indirect Cost Allocation	Allocated costs for services provided to the entire enterprise, and not solely to a LOB.
Intercorporate Services Agreement (ISA)	Intercorporate agreement between EI and EGI pursuant to which EI provides services and related Central Functions cost allocations to EGI in accordance with the ARC.
Line of Business (LOB)	For EGI, represents a sub-segment within a Segment. EGI's rate-regulated operations are a LOB within the EI Gas Distribution & Storage Segment.

[1] https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Affiliate-Relationships-Code-for-Gas-Utilities-ARC-20101125.pdf

Term	Definition
Three-Prong Test[2]	Framework developed by the OEB to determine if shared corporate service costs are in the interest of ratepayers based on cost prudence, cost allocation methodology, and cost benefit analysis.
Segment	Enbridge's core businesses, comprised of: Liquids Pipelines, Gas Transmission & Midstream, Gas Distribution & Storage, Renewable Power Generation, Energy Services[3] and Eliminations & Other. EGI belongs to the Gas Distribution & Storage Segment. Synonymous with Business Unit as described in the ISA.
Service Category	A grouping of Centralized Function Cost Centres into "like" services that are provided to Segments.
Modified Three Factor Formula (3FF)	Indirect cost allocation method that utilizes gross revenues (or net revenues where applicable), gross book value of property, plant and equipment and payroll to determine the consumption of services by a LOB.

[2] https://www.oeb.ca/documents/cases/Cr492-03/decision.pdf

[3] Enbridge Inc.'s Energy Services segment provides physical commodity marketing and logistical services to North American refiners, producers, and other customers. This is separate and distinct from the Energy Services function within Enbridge Gas, which is focused on all the storage and transportation elements and services offered through Enbridge Gas – with a focus on gas flowing into, out of and within Ontario.

2. Executive Summary

Enbridge Inc. (EI or Enbridge) is a North American energy infrastructure company. Enbridge is composed of six Segments[4]: Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation, Energy Services[5], and Eliminations & Other. Enbridge Gas Inc. (EGI) belongs to the Gas Distribution and Storage segment. Enbridge has established Central Functions (CF) that provide conventional corporate shared services to its affiliate companies and allocates the CF costs amongst the service recipients using an internally developed Central Functions Cost Allocation Methodology (CFCAM).

EGI, a wholly owned subsidiary of EI, is Canada's largest natural gas storage, transmission, and distribution company. As an affiliate, EGI receives services from the CFs. EGI is based in Ontario and is regulated by the Ontario Energy Board (OEB). The OEB's Affiliate Relationships Code for Gas Utilities (ARC) sets standards that are intended to minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities in situations where affiliate companies exist.

EGI retained Guidehouse to review and assess the CF cost allocations received by EGI through the CFCAM for alignment with principles of the ARC, using the OEB's Three-Prong Test (defined in Section 3.1.2). Guidehouse performed a comprehensive evaluation of the 2022 CF cost allocations budget, referred to for the remainder of this report as "2022 Budget", and the underpinning CFCAM. Guidehouse relied on the analysis and findings derived from its evaluation of the 2022 Budget to perform a reasonability assessment of the 2022 and 2024 CF cost allocations forecasts (2022 Forecast and 2024 Forecast, respectively). The 2022 Forecast[6] presents updated cost projections as compared to the 2022 Budget and is the basis for the 2024 Forecast.

Guidehouse's methodology and results are summarized in Sections 5.2, 6 and 7 of this report. The approach for the assessment of the 2022 Budget relied on a series of analytical procedures, inquiries, and discussions with EI and EGI employees. The assessment consisted of:

1. Review of the CF cost allocations received through the CFCAM and related documentation
2. Assessment of the CFCAM's alignment to cost allocation principles and regulatory guidance
3. Interviews with service recipients and providers to assess alignment with the Intercorporate Services Agreement (ISA) between EI and EGI
4. CFCAM testing against the OEB's Three-Prong Test: cost incurrence, cost allocation (causation), and relative benefits to cost which was further supported by an industry comparative review of select CF costs
5. Review of CFCAM and integrity analysis of the CFCAM

[4] See Section 1 for detailed definitions used in this report

[5] Enbridge Inc.'s Energy Services segment provides physical commodity marketing and logistical services to North American refiners, producers, and other customers. This is separate and distinct from the Energy Services function within Enbridge Gas, which is focused on all the storage and transportation elements and services offered through Enbridge Gas – with a focus on gas flowing into, out of and within Ontario.

[6] 2022 Forecast includes the benefit of two months of 2022 actuals and 10 months of forecast (2+10)

6. Assessment of the CF services and costs for compliance with ARC requirements

Based on Guidehouse's industry experience, combined with its assessment of the CFCAM implementation, Guidehouse concluded that the CFCAM is based on a robust transfer pricing methodology and delivers reasonable cost allocations that follow the ARC principles and align to common industry practice.

The adjusted allocated costs for the 2022 Budget, as well as forecast allocations for 2022 and 2024 as detailed in Table 2-1, are reasonably incurred, are established through cost drivers that observe the key principle of cost causation and offer benefits that equal or exceed costs for EGI and its ratepayers. These costs pass the Three-Prong Test.

Table 2-1 Summary of CF Cost Allocations Assessment[7]

Assessment Period	A	B	C	D = A + B + C	E	F = D - E
	Direct Charge	Directly Attributable	Indirect Costs	Total Allocations	Adjustments (Indirect)	Allocation After Adjustments
2022 Budget	$ 4,898,173	$ 183,525,324	$ 135,293,129	$ 323,716,626	$ 4,929,037	$ 318,787,589
2022 Forecast	$ 4,818,121	$ 176,367,388	$ 155,525,189	$ 336,710,698	$ -	$ 336,710,698
2024 Forecast	$ 5,042,298	$ 199,986,660	$ 167,413,398	$ 372,442,357	$ -	$ 372,442,357

[7] Rounding was applied to each table of the report, resulting in small rounding differences.

3. Introduction

Enbridge has centralized a number of corporate functions that provide shared services (Central Functions or CF) on behalf of its affiliates. The costs of these CFs are allocated among affiliates based on an internally developed CFCAM. See Table 3-1 for service descriptions.

3.1 Regulatory Framework

3.1.1 OEB's Affiliate Relationships Code for Gas Utilities

EGI is regulated by the OEB. The OEB regulates affiliate costs for rate-making purposes based on its Affiliate Relationships Code for Gas Utilities[8] (ARC), originally issued on July 31, 1999, and last revised on November 25, 2010. The purpose of the ARC is to set out the standards and conditions for the interaction between rate regulated gas distributors, transmitters and storage companies and their respective affiliated companies. The principal objectives of the ARC are to enhance a competitive market while at a minimum keeping ratepayers unharmed by the actions of energy distributors, transmitters, and storage companies with respect to dealing with their affiliates. The standards established in the ARC are intended to minimize the potential for the OEB regulated business of EGI to cross-subsidize competitive or non-monopoly activities.

3.1.2 OEB's Three-Prong Test

The Three-Prong Test is a method defined in the OEB Decision with Reasons dated March 20, 1997 (EBRO 493/494) to help with cost allocation decisions. Each prong is assessed only in the event of a 'passing' grade for a previous prong. The OEB's Three-Prong Test sets the framework for determining if CF costs are just and reasonable for Ontario ratepayers based upon the prudence of the services received, the appropriateness of the allocation methodology, and the relative benefits of the service weighed against its costs.

Prong One: Cost Incurrence

Prong One tests if the allocated costs are prudently incurred by, or on behalf of, EGI for the provision of a service required by Ontario ratepayers. Costs will not pass this test if they relate to activities which:

- Go beyond the scope required for a utility;
- Are associated with overall governance from a shareholder perspective or "minding the investment"; or
- Represent additional and superfluous management layers.

Prong Two: Cost Allocation

Prong Two tests if the proposed CF cost allocations are allocated appropriately to the affiliates based on the application of Cost Drivers, supported by principles of cost causality.

[8] https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Affiliate-Relationships-Code-for-Gas-Utilities-ARC-20101125.pdf

Prong Three: Cost Benefit

Prong three tests if the benefits to EGI's ratepayers equal or exceed the costs. The OEB has accepted the following four categories as the basis for assessing quantifiable benefits:

- Replacement benefits – the services provided replace an equivalent service at equal or lower cost.
- Synergistic or linkage benefits – the services allow EGI to reduce costs by means of being part of the larger group and operating in concert for the procurement of products and services.
- Revenue enhancement or cost recovery benefits – EGI's activities and capabilities provide value to other affiliates for which payment in cash or kind is received.
- Stand-alone benefits – strategic actions and activities instituted by Enbridge that produce direct value to the affiliates.

3.1.3 Intercorporate Services Agreement (ISA)

The ISA sets out the terms and conditions applicable to the provision of CF services to EGI, in accordance with the ARC. The current ISA went into effect on January 1, 2019, terminating all previous agreements. The agreement automatically renews on an annual basis and will be replaced following its expiry on December 31, 2023.

The ISA provides the scope of services and the contractual framework by which the CF costs are allocated. Key components include:

- Terms and Conditions
- Description of the CFCAM including methods of allocation
- Description of services provided

3.2 Central Functions Descriptions

Table 3-1 summarizes Enbridge's CFs and the services they provide.

Table 3-1 Central Functions Service Descriptions

Central Function	Service Categories	Service Description
Aviation	• Business Travel • Pipeline Patrolling	• Provide air transportation service in response to company needs and conduct operations to the highest safety standards. • Provide pipeline patrolling surveillance over pipelines.

Central Function	Service Categories	Service Description
Corporate Development Office (CDO) [9]	• Strategy • Corporate Development • Investment Review • Investor Relations	• Develop and disseminate a Strategic Plan to position the company for sustainable growth and value creation. • Provide analytical decision support to investment decision makers. • Assess and create investment opportunities for growth. • Integrate finance, communication, marketing and securities law compliance to enable the most effective communication between Enbridge, the financial community, and other constituencies.
Enterprise Asset and Work Management (EAWM)	• Enterprise Resource Planning	• Manage the lifecycle of physical assets and equipment in order to maximize its life, reduce costs, improve quality and efficiency, health of assets and environmental safety. • Develop and implement advanced work management capabilities to deliver work in a more effective and efficient manner.
Executive	• Executive	• Make major corporate decisions, manage operations and Central Functions, and overall resources. • Provide strategic and executive leadership over all Enbridge companies including EGI. • Liaison between EI and the investment community to improve access to capital markets and funding to support EGI's operations and approved capital structure. • Act as the main point of communication between the Board of Directors and corporate operations.

[9] CDO Function moved to the Finance Central Function partway through 2022.

Central Function	Service Categories	Service Description
Finance	• Gas Distribution Finance • General Finance • Management Reporting, Planning and Budgeting • External Reporting • Accounts Payable • Capital Asset Accounting and Reporting • Treasury • Credit • Tax Services • Audit Services • Risk Assessment • Risk Control and Contracts • Accounting Policy and Internal Controls • Finance Transformation	• Provide information on actual and future financial performance, partner in decision making, and manage finance operations for the enterprise in addition to EGI specifically. Includes financial and management reporting, and regulatory accounting. • Execute transactional accounting processes including invoice processing and management of capital asset reporting. • Execute capital, credit, tax, audit and risk assessment and control programs. • Maintain control environment and accounting policies, including enterprise-wide policies. • Support strategic and practical initiatives within the Finance function.
Real Estate & Workplace Services (REWS)	• Real Estate (Chatham/Toronto/Edmonton) • Real Estate (General)	• Provide a cost-effective workplace that enables the business to achieve its strategic objectives.
Human Resources (HR)	• Advisory Service and Recruitment • Payroll and MyHR • HR Business Partners • Rewards and Analytics • Benefits and Pension Administration, Health Services, Operational Performance and Quality Assurance • Talent Management • Enterprise Cost	• Provide advisory support for leader and employee relations and recruitment. • Provide support for payroll, compensation, and benefits programs. • Execution of talent management programs. • Overall oversight of the Enterprise HR program.
Legal	• Gas Utilities Law • Ethics and Compliance • Technology Information Systems (TIS) and Supply Chain Management (SCM) Legal Services • Corporate Law Services • Corporate Secretary Services • GTM and LP Law	• Provide comprehensive legal services to support corporate, commercial, litigation, regulatory and other business working with external counsel as necessary.

Central Function	Service Categories	Service Description
Public Affairs and Communications (PAC)	• Enterprise Communications • Corporate Social Responsibility and Community Investment • External Affairs and Policy • Stakeholder & Indigenous Engagement • Public Awareness	• Engagement strategies that support the business objectives including Enterprise Communications, Corporate Social Responsibility, community investment guidance and industry relations. • Strategic advocacy in support of projects, operations and public policy including public awareness outreach, stakeholder and Indigenous engagement and external affairs.
Safety and Reliability (S&R)	• Safety • Centres of Excellence	• Supports safety training, safety consulting services, regulation, and contractor programs. • Provides support for Risk, Management, and Governance within Enterprise Safety and Operational Reliability.
Supply Chain Management (SCM)	• Gas Distribution Operations • Materials Management and Logistics • Direct Category Management • Indirect Category Management • Planning, Governance and Technology	• Primary point of contact for internal customers. • Manage supply chain planning and supply chain execution. • Manage and negotiate spend and discounts for the enterprise. • Define, recommend, and execute category strategies for key categories of direct and indirect goods and services.
Technology Information Systems (TIS)	• Gas Distribution Application Management and Support • Enterprise Application and Management Support • LP Application and Management and Support • Core Infrastructure Operations • Gas Distribution Operational Technology • Cyber Security • IT Service Management and Client Services • Network Services • Mobility • Technology Direction and Governance	• Manage the systems and applications that support the whole enterprise in addition to EGI. • Various TIS-related services including core infrastructure operations, operational technology, cyber security, IT service management and client services, network services, mobility, and technology direction and governance.

Central Function	Service Categories	Service Description
Benefits[10]	NA	• Represents pension, long-term incentive, health, and other benefit costs.
Depreciation[10]	NA	• Cost of shared assets that provide benefit to the entire enterprise.
Insurance[10]	NA	• Represents insurance premiums.

[10] Costs managed by CFs

4. Central Functions Cost Allocation Methodology (CFCAM)

4.1 Need for Cost Allocation

As a large and complex enterprise with many affiliate companies, Enbridge has centralized certain functions and provides the associated services to affiliates, including EGI, in replacement of EGI's internal provision of services. Enbridge has 12 Central Functions that provide advantages to Enbridge's entire enterprise including EGI. Central Functions provide subject matter expertise, strategic oversight and planning, corporate governance, sharing of best practices and economies of scale for affiliates. Central Functions create value for Ontario ratepayers by avoiding costs of discrete and/or third-party services procurement that a stand-alone utility would require.

4.2 Principles of Cost Allocation

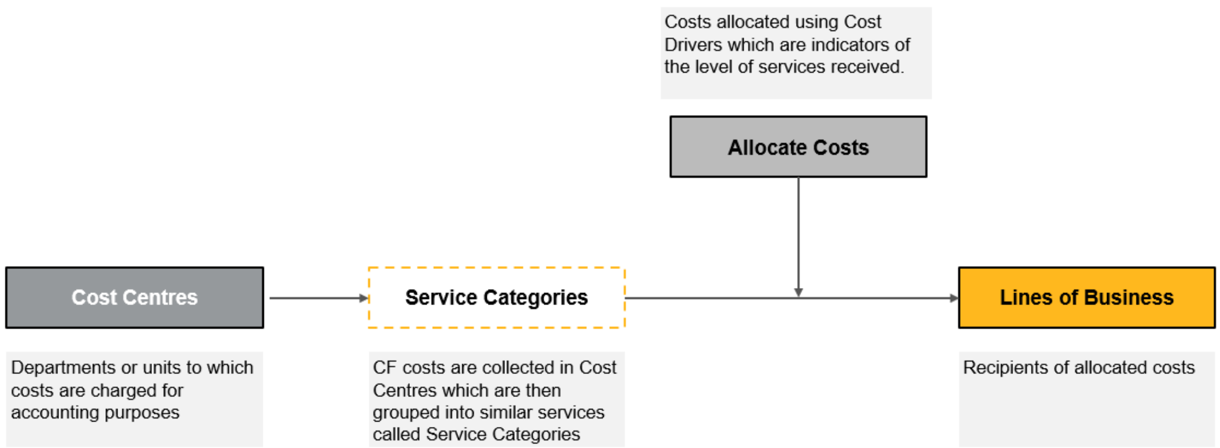
In developing the CFCAM, Enbridge considered the following guiding principles which are aligned with industry practice and the intent and tenets of the ARC and other relevant regulation:

Consistent	Consistent in employing a standardized methodology across all segments
Regulatory and Joint Venture Compliant	Complies with regulatory requirements and joint venture agreements
Tax Compliant	Meets taxation authority requirements
Simple	Simple to understand and administer, and adheres to the methodology
Transparent	Transparent in conveying the source of allocated costs and the basis for allocating costs
Fair	Reasonable to Business Partners and affiliates receiving allocations
Manageable and Practical	Adaptable to changes in business while leveraging automation to limit manual intervention
Accurate	Meets the requirements for Cost Recovery and Compliance

4.3 Methods of Cost Allocation

In the CFCAM, costs are collected in Cost Centres which are then grouped into similar services called Service Categories. Service Categories form a total Cost Pool that is ultimately allocated to individual LOBs. The allocations are based on the principle of cost causation and use Cost Drivers, whereby costs are driven by the activities required to provide the service. The diagrams and definitions within this report are simplified representations of the allocation process. See Appendix B for a more detailed depiction of the CFCAM.

Figure 1 Enbridge Simplified CFCAM



There are three types of CF costs, of which two are allocable:

- **Directly Attributable Costs** – Costs that are specifically attributable to a Segment, Sub-segment, or LOB due to the direct provision of service and clear ability to demonstrate cost causation. See Appendix B for a more detailed definition.
- **Indirect Costs** –Allocation of costs for services that are provided by Centralized Functions to the whole enterprise and not specifically related to a single Segment, but from which all Segments benefit. These costs are allocated through Enbridge's Modified three-factor formula (M3FF). See Section 4.4.1 for details.
- **Direct Charge Costs** – Recorded directly in the LOB to which they pertain. Hence, no allocation is required. Legal, PAC, Audit and S&R costs include Direct Charge Costs.

4.4 Cost Drivers

Cost Drivers represent activities related to the cost incurred to provide a service and are indicative of the level of services received. In selecting the Cost Drivers, Enbridge considered the following tenets:

- **Causality:** Cost Driver changes directly affect the costs incurred in the Service Category.
- **Materiality:** The Cost Driver influences the majority of the services and costs within the Service Category.
- **Quantifiability:** The Cost Driver is easily and accurately definable over any period.
- **Availability:** The Cost Driver data is readily available. Ideally, the necessary information is available and tracked in IT systems and can be obtained when required by CFCAM users.

4.4.1 Cost Driver Types

The CFCAM utilizes a combination of three types of Cost Drivers which are common in the utilities industry:

- **Consumption-based** – allocates costs on a variable basis.
- **Static** – allocates costs on a fixed basis.
- **Blended and Multi-factor Formula Allocation –** underpinned by the concept that the size, scope, and organization's profits impact the level of CF services that are likely to be required. Therefore, a multifactor formula creates a robust proxy for cost causation through representation of scale by people, capital and/or assets, and profitability of an organization. The costs provide benefits to the entire organization and as such a Multi-factor Formula, such as Three-Factor Formula (3FF), is an appropriate Cost Driver.

Three-Factor Formula Allocation

Using a three-factor formula (3FF) as a general allocator is a common practice in the utility industry[11]. The 3FF, also referred to as the "Massachusetts Formula" is comprised of Plant and Equipment (PP&E), Direct Labour Expenses, and Gross Revenues which are equally weighted. The implementation of 3FF can vary across utilities as different measures are used to represent the three core factors. The "Modified Massachusetts Formula" consists of variations of the three factors identified above. Utility regulatory commissions across the United States have accepted both the Massachusetts Formula and Modified Massachusetts Formula[11]. The 3FF has also been implemented by other utilities[12] within Canada.

In the case of Enbridge, a modified three-factor formula (M3FF) is used. The three factors used in Enbridge's M3FF allocation formula are:

1. **Payroll** – Consists of base pay and overtime for both permanent and contract employees.
2. **Gross Book Value of PP&E** – Gross book value of PP&E excluding any material impairments.
3. **Revenue** – The term "revenues" means gross revenues for each LOB, except for Energy Marking businesses, Gas Distribution business (including EGI), and Gas Pipelines and Processing businesses for which net revenues (gross revenues minus commodity or gas distribution cost) is used. For EGI, gas distribution cost is a flow-through cost. Therefore, net revenue, instead of gross revenue, is considered to be a more reasonable basis for allocation.

For the remainder of this report, the term "3FF" is referencing the M3FF as defined by Enbridge.

[11] National Grid March 30, 2012 Filing – Revisions to Cost Allocation Methodologies Page 3

[12] ATCO, EPCOR, Fortis B.C., Hydro One, AltaGas, SEMCO Energy (prior to being acquired by AltaGas) and Pacific Northern Gas

Table 4-1 defines all Cost Drivers used in the CFCAM.

Table 4-1 Cost Drivers

Cost Driver	Definition
3FF	The three factors of LOB Payroll, Gross Book Value of PP&E and Revenue are blended and used to allocate certain CF costs. The term "Payroll" comprises base pay and overtime for both permanent and contract employees. See definitions for Revenue and Gross Book Value of PP&E below.
Balance Sheet Debt	The size of a Segment's debt compared to Enterprise debt.
Capacity Utilization	For each major geographic region, the number of a LOB's employees physically located in a region in comparison with total employees from all LOBs physically located in that region. The term "employees" consists of permanent and contract employees and excludes Corporate employees.
Directly Attributable	Refers to costs that are specifically attributable to a Segment, Sub-segment, or an LOB. See Appendix B for detailed definition.
Donations Value	The factor of the cost of donations incurred by a Segment compared to the total cost of donations incurred across the Enterprise.
Estimated Salary by LOB	Total estimated base pay and overtime pay for both permanent and contract employees for an LOB compared to Enterprise-wide.
Flying Hours	The number of flying hours dedicated to each LOB compared to total Enterprise flying hours.
Gross Book Value of PP&E	The factor of gross PP&E for a LOB compared to gross PP&E of the Enterprise.
High-Level Time Forecasting	The proportion of the total time spent by a Service Category in servicing a specific Segment.
HR Business Partners Headcount	The number of HR Business Partners assigned to a Segment compared with the total number of HR Business Partners in the HR Central Function.
HR Case Volume	The factor of the number of cases completed for a Segment compared to Enterprise-wide cases. In addition, a further allocation percentage is added to distribute cases originating from corporate services and projects to each Segment.
Network Circuit Usage	The amount of network consumption for a Segment compared to the total network consumption across the Enterprise. Consumption refers to the percentage of usage of service.
Number of Invoices	Number of invoices processed by Accounts Payable for an LOB compared to total number of invoices processed by Accounts Payable across the Enterprise.
Revenue	For EGI, the factor of net revenue compared to total revenue across the Enterprise.

Cost Driver	Definition
	The term “revenues” means gross revenues for each LOB, except for Energy Marketing businesses, Gas Distribution business (including EGI), and Gas Pipelines and Processing businesses for which net revenue (gross revenue minus commodity or gas distribution cost) is used.
Spend	Total sourceable Capital and Operating & Administrative purchases for a Segment compared to Enterprise-wide.

5. Scope of Work

Guidehouse conducted an independent review of the ISA and CFCAM to provide an opinion as to how they observe and respect the OEB's past decisions, the ARC, and the Three-Prong Test. The intent of the assessment was to identify potential areas of non-conformity with the principles of the OEB's ARC and by extension, good transfer pricing and cost allocation practices.

This study does not include an exhaustive or comprehensive cost benchmarking exercise. However, given Guidehouse's industry experience and technical expertise, the review leveraged publicly available information regarding utility costs to compare EGI's CF costs to similar costs of comparable utilities in Canada and the U.S for reasonability. This approach is consistent with similar studies that Guidehouse has completed in the industry.

5.1 Guidehouse Expertise

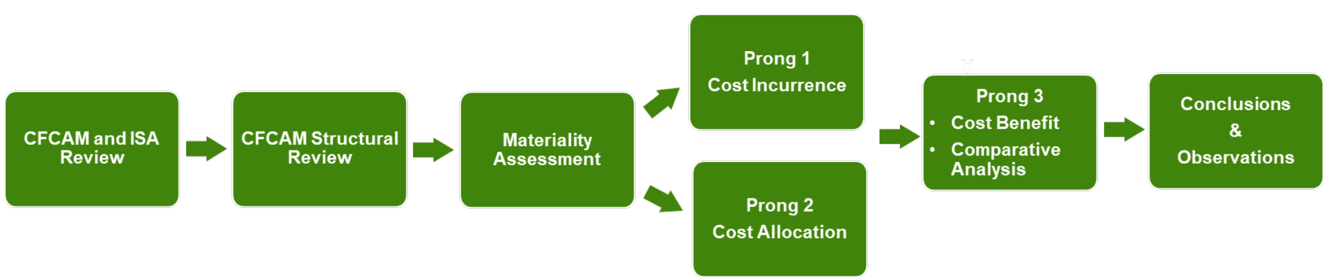
To complete this assessment, Guidehouse assembled a team with extensive experience and expertise in shared services costs, allocation methodologies, the OEB's ARC, analysis of regulatory applications and decisions, and knowledge of Enbridge's business and shared services.

Guidehouse has successfully delivered past independent cost reasonableness reports and comparative cost analysis. Guidehouse also has prior experience with centralized shared services and cost allocation assessment frameworks that have been filed and accepted by regulators across North America. Guidehouse has worked with EGI on several past engagements and has a robust understanding of EGI and its lines of business and functional areas.

5.2 Guidehouse Approach and Methodology

Guidehouse's methodology, as outlined below, included a combination of documentation review, interviews, and analytic Three-Prong testing. Figure 2 outlines the approach Guidehouse used to complete a detailed assessment of the 2022 Budget[13].

Figure 2 Guidehouse Approach to Scope of Work



[13] Guidehouse's approach and methodology for assessment of 2022 and 2024 Forecast is detailed in Section 9 of this report.

5.2.1 CFCAM and ISA Review

Guidehouse reviewed the ISA to establish its compliance with the ARC, its alignment with regulatory precedents and past decisions within and outside of Ontario, as well as common industry practices.

The ISA review also informed how the CFCAM should be assessed in the context of the Three-Prong Test, establishing support for incurrence and/or cost drivers.

5.2.2 CFCAM Structural Review

The core model tenets of the CFCAM, as applied to EGI, were reviewed for reasonability, integrity, and consistency with OEB precedent, and generally acceptable regulatory and accounting practices for cost allocation. Guidehouse assessed alignment of Enbridge's objectives, guiding principles, and intended implementation with industry common practice. The underlying CFCAM formulas, as well as the application of Cost Drivers, were functionally tested to ensure allocation outcomes were consistent with the model.

5.2.3 Materiality Assessment

Guidehouse assessed CF cost allocations in all Service Categories. A materiality threshold was applied for the purpose of conducting interviews with service providers and recipients to ensure focused and effective assessment efforts.

5.2.4 Three-Prong Test Assessment of 2022 Budget[14]

Guidehouse conducted detailed analysis of CF allocations. The approach for this assessment is summarized below.

CF Assessment Approach

Guidehouse conducted a review of the CFCAM and the 2022 Budget to assess if services as detailed in the ISA were incurred prudently on behalf of EGI ratepayers, demonstrated causality between the Cost Drivers and allocated costs, and if costs were fair, reasonable and their benefits outweighed the costs. A review of the CFCAM, underlying calculations, related documents, and inquiries with Enbridge formed the basis for Guidehouse's assessment of the CFCAM, and how costs collected in each Cost Centre were ultimately allocated.

To supplement, Guidehouse reviewed Enbridge organization charts, inquired about organizational service levels and their functions, reviewed Cost Centres, and the nature of costs. Interviews were conducted with both service providers and recipients of each CF who were knowledgeable about the services provided to and received by EGI. The objectives of the interviews were to discuss in detail, the CF services, Cost Drivers used in allocation, benefits to EGI, and any significant changes from previous years' service levels (See Appendix C for a list of attendees for each interview).

The following approach was taken to assess Depreciation, Insurance and Benefits, which are costs managed by CFs:

[14] Guidehouse's assessment of 2022 and 2024 Forecast CF allocations are discussed in Section 9

- **Depreciation** – Depreciation relates to three types of shared assets: TIS, Real Estate and Aviation. Guidehouse inquired and conducted meetings to understand the nature of all enterprise assets generating depreciation and the Cost Driver for allocating depreciation. As enterprise IT assets account for the majority of Depreciation, Guidehouse performed a detailed review of over 50% of assets generating depreciation. Through analysis performed, Guidehouse was able to assess compliance with the Three-Prong Test.

- **Insurance** – Guidehouse performed inquiries to understand the enterprise-wide premiums generating the insurance costs allocated to EGI and related Cost Drivers. In addition, Guidehouse performed a comparative analysis to assess the reasonability of insurance costs allocated to EGI. Through analysis performed, Guidehouse was able to assess compliance with the Three-Prong Test.

- **Benefits** – Guidehouse performed inquiries regarding the types of benefit costs allocated to EGI. Guidehouse did not perform a comparative analysis for benefit cost allocations, as Enbridge has indicated it will perform its own independent benchmarking of benefits in support of EGI's 2024 rebasing application. Through analysis performed, Guidehouse was able to assess compliance with the Three-Prong Test.

Allocated costs for services must ultimately be within a reasonable range relative to the utility's costs to perform the services itself or to obtain the services from third parties at a fair market rate. As part of the Three-Prong Test review, Guidehouse first assessed the materiality of the allocated costs and, where appropriate, performed a Cost Benefit Test. Costs were compared with peer utilities in Canada and the US to determine the cost effectiveness of services as compared to industry standards. If the normalized costs were commensurate with peers, Guidehouse concluded that EGI is receiving the service benefits at a reasonable cost.

Guidehouse identified and prioritized comparators based on:

- Availability of public data/information
- Scale and complexity of utility
- Understanding of the services and cost allocation approaches
- Strength of Guidehouse's relationships with comparator utilities

The interview discussions informed the need and the benefit of the services and combined with the comparative analysis, demonstrated that EGI is receiving the benefits that are needed by the utility and are acceptable shared services as defined by the ARC.

As a result of this assessment, Guidehouse then adjusted, if necessary, each allocated cost for prudence (Prong One Test, Cost Incurrence) and appropriate cost allocation (Prong Two Test, Cost Allocation) and determined if benefits outweighed costs (Prong Three Test, Cost Benefit). Guidehouse provided rationale and explanation for each adjustment in Tables 6-4 and 6-5 of this report.

Guidehouse developed a sample template (Figure 3, below) as a tool to conduct testing, summarize and present relevant information and assessment findings. Explanations in **blue** font provide some context for the content that appears in each completed service review.

Completed service reviews and detailed consolidated results of these reviews are set out in Appendix A.

Figure 3 CF Analysis Sample Template

Central Function: Description	
Service Categories	As detailed in Table 3-1
Service Description	As detailed in Table 3-1
Central Functions Cost Allocation per 2022 Budget	Direct Charge / Directly Attributable / Indirect / Total / Recommended Adjustments / Allocation After Adjustment A / B / C / D = A + B + C / E / F = D - E \$X / \$X / \$X / \$X / \$X / \$X The total of all Direct Charges, Directly Attributable, and Indirect Charges less Recommended Adjustments are the net Allocations to EGI After Adjustments.
Prong One Test Determine if charges to EGI are prudently incurred. Grade Pass / Fail	**Cost Incurrence Review** Guidehouse opinion and explanation
Prong Two Test Determine if charges to EGI are appropriately allocated. Grade Pass / Fail	**Cost Allocation Review** Guidehouse opinion and explanation.
Prong Three Test Determine if the benefits to ratepayers exceed the cost. Grade Pass / Fail	**Cost Benefit Review** Guidehouse assessment of benefits received as described by Service Recipients and Comparative Analysis for select CF allocations.
Guidehouse Conclusions	Status of Guidehouse Prong test results. Guidehouse proposed adjustment to the 2022 Budget allocation (if applicable).

5.3 Limitations of the Review

Guidehouse's review consisted of inquiry and analytical procedures related to information provided by Enbridge. Guidehouse relied on the representation of the staff, management, and executives of the Enbridge companies, and therefore EGI retains responsibility for the accuracy and completeness of the data provided.

Guidehouse did not independently audit or verify the data received. Guidehouse reviewed the CFCAM model itself and did not perform a detailed examination of underlying transactions, or validate source records, except as specifically noted in our approach.

6. Findings and Results

6.1 Review of ISA for Alignment to ARC

The ISA establishes the contractual service relationship between EI and EGI for the CFs. The ISA governs CF activities and service levels. Guidehouse conducted a review of Section 2.2.1 of the ARC which addresses Sharing of Services and Resources.

Table 6-1 summarizes Guidehouse's assessment of how the ISA adheres to each element of Section 2.2.1 of the ARC.

Table 6-1 ISA Review

ARC Standard	Guidehouse Assessment	Result
2.2.1 Where a utility shares services or resources with an affiliate it shall do so in accordance with a Services Agreement	Regularly reviewed ISA between EI and EGI observes the principles and intent of the ARC. EGI has indicated the intent to update the ISA with organizational changes, services, and definitions in the CFCAM.	Pass
The Services Agreement shall include documentation of:		
a) the type, quantity and quality of service;	The ISA between EI and EGI summarizes the type of services to be provided and highlights the tenets of service levels transparently.	Pass
b) pricing mechanisms, which shall be consistent with section 2.2.5 and section 2.3;	Pricing mechanisms are established by the CFCAM. This is in alignment with the terms set out in section 2.3. The current ISA shall not extend beyond December 31, 2023, unless otherwise approved by the OEB.	Pass
c) cost allocation mechanisms, which shall be consistent with section 2.3.11.3;	A well documented and tested cost allocation approach is used to allocate shared service costs using a reasonable fully allocated cost-based approach as described in this report.	Pass
d) information disclosure and confidentiality arrangements, which shall be consistent with section 2.3.1.2;	Parties of the ISA acknowledge that the agreement is subject to any rule or order applicable to EGI made by the OEB. Also, the requirements in section 2.3.1.2 of the ARC are incorporated in section 3 of the ISA.	Pass

ARC Standard	Guidehouse Assessment	Result
e) Consideration for the apportionment of risks (including risks related to under or over provision of service);	There are several provisions in the ISA that address the apportionment of risk to ensure sufficient oversight, determination, and supervision of how services are provided, and costs allocated through the CFCAM and the ISA. • Section 15 – sets out basic requirements for the Service Provider to provide services in the manner described. • Sections 10 & 11 – set out limitations on liability for how services are provided and if the standard is breached, what indemnification is warranted. • Section 14 – sets out what happens in the event of a force majeure. • Section 16 – sets out how disputes related to performance of services and cost allocations are handled. President of EGI can make a final binding determination if the parties cannot otherwise resolve. • Section 5 - EI and EGI determine the allocations in consultation with each other and true-ups may occur in accordance with the CFCAM. • Schedule 2 (CFCAM Description) – In section 8, it is noted that a CF manager is responsible for several items related to how services are provided and ensuring cost allocations are reflective of the benefits received.	Pass
f) a dispute resolution process for any disagreement arising over the terms or implementation of the Services Agreement	The ISA summarizes procedures for resolution of disputes that may arise from the terms or the implementation of services under the agreement.	Pass

6.2 2022 Budget CFCAM Review Summary

Guidehouse performed a comprehensive evaluation of EGI's 2022 CF cost allocations budget as summarized below.

Table 6-2 Summary of 2022 Budget Before Adjustments

	2022 Budget			
Central Function	**Direct Charge**	**Directly Attributable**	**Indirect Costs**	**Unadjusted Total**
Aviation	-	11,288	2,248,940	2,260,228
CDO	-	430,503	2,731,839	3,162,342
EAWM	-	-	1,682,547	1,682,547
Executive	-	-	1,041,258	1,041,258
Finance	1,460,819	24,784,765	9,036,439	35,282,023
REWS	-	28,098,028	-	28,098,028
HR	-	22,890,498	-	22,890,498
Legal	2,802,354	3,384,958	8,109,619	14,296,931
PAC	635,000	5,155,876	-	5,790,876
S&R	-	7,062,208	-	7,062,208
SCM	-	7,771,386	-	7,771,386
TIS	-	55,186,406	45,990,773	101,177,179
Benefits	-	6,700,727	44,769,432	51,470,159
Depreciation	-	-	19,682,282	19,682,282
Insurance	-	22,048,681		22,048,681
Total	**$ 4,898,173**	**$ 183,525,324**	**$ 135,293,129**	**$ 323,716,626**

Review Summary

Guidehouse's assessment resulted in adjustments to Indirect Costs in three CFs and Depreciation, totaling $4,929,037 which represents 1.5% of total allocated costs. Prong One adjustments totalled $2,517,733 and Prong Two adjustments totalled $2,411,305. All CFs passed the Prong Three Test post adjustments. Table 6-3 summarizes the result of Guidehouse's CFCAM review.

Table 6-3 CFCAM Review Summary – 2022 Budget

Central Function	2022 Budget (Before Adjustments)	Prong One		Prong Two		Prong Three		Total Prong Adjustments	Allocation After Adjustments
		Assessment	Adjustment	Assessment	Adjustment	Assessment	Adjustment		
	(A)		(B)		(C)		(D)	(E) = (B)+(C)+(D)	(F) = (A)- (E)
Aviation	$ 2,260,229	Pass (With Adjustment)	$ 2,248,940	Pass	$ -	Pass	$ -	$ 2,248,940	$ 11,288
CDO	$ 3,162,342	Pass	$ -	Pass (With Adjustment)	$ 808,488	Pass	$ -	$ 808,488	$ 2,353,855
EAWM	$ 1,682,547	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 1,682,547
Executive	$ 1,041,258	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 1,041,258
Finance	$ 35,282,022	Pass	$ -	Pass (With Adjustment)	$ 1,602,817	Pass	$ -	$ 1,602,817	$ 33,679,205
REWS	$ 28,098,028	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 28,098,028
HR	$ 22,890,498	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 22,890,498
Legal	$ 14,296,930	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 14,296,930
PAC	$ 5,790,876	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 5,790,876
S&R	$ 7,062,208	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 7,062,208
SCM	$ 7,771,387	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 7,771,387
TIS	$ 101,177,179	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 101,177,179
Benefits	$ 51,470,159	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 51,470,159
Depreciation	$ 19,682,281	Pass (With Adjustment)	$ 268,792	Pass	$ -	Pass	$ -	$ 268,792	$ 19,413,489
Insurance	$ 22,048,681	Pass	$ -	Pass	$ -	Pass	$ -	$ -	$ 22,048,681
Total	**$ 323,716,626**		**$ 2,517,733**		**$ 2,411,305**		**$ -**	**$ 4,929,037**	**$ 318,787,589**

6.2.1 Prong One Test Results: Cost Incurrence

The objective of the Prong One Test is to reasonably assess whether allocated costs are prudently incurred by, or on behalf of EGI for the provision of services required for Ontario customers. Furthermore, costs cannot be related to minding the investment, result from superfluous or redundant management layers, or go beyond the scope required for a utility.

As part of this test Guidehouse performed extensive analysis of costs allocated to EGI for services provided from 62 Service Categories. This assessment included detailed functional area review and inquiries with respect to organizational structure and the nature of costs and services in each Cost Centre. Using the guidelines of the Prong One Test, Guidehouse determined that a total of $2,517,733 of costs from two Service Categories were not prudently incurred on behalf of EGI. All other costs incurred did not go beyond a scope found to be reasonably required for a standalone utility and are representative of common functional areas of corporate services of utility organizations. These costs were not found to be associated with "minding the investment", or representative of additional and superfluous management layers.

For detailed analysis of each CF, refer to Appendix A.

Table 6-4 Summary of Prong One Test Adjustments

Central Function	Service Category	Budgeted Allocation	Adjustment	Adjustment Rationale
Aviation	Business Travel (Passengers)	$2,248,940	$2,248,940	Portion of Aviation CF allocation deemed not prudent. Usage of corporate jet for business travel is unnecessary for a utility solely based in Ontario.
Depreciation	Depreciation	$19,682,281	$268,792	Corporate jet depreciation related to business travel and depreciation of certain IT asset not providing benefit to EGI is deemed not prudent
Total		**$21,931,222**	**$2,517,733**	

Guidehouse Cost Incurrence Findings:

Guidehouse found that $321,198,894 of costs allocated to EGI passed the Prong 1 Test and were for the provision of services required by an organization with the scale and complexity of EGI. Guidehouse determined certain costs from two Service Categories were not prudently incurred.

6.2.2 Prong Two Test Results: Cost Allocation

The allocated costs that passed the Prong One Test ($321,198,894) were carried forward into the Prong Two Test.

The objective of the Prong Two Test is to ensure that costs have a direct or reasonable causal relationship to EGI's utility operations, and that an appropriate Cost Driver is used to proxy cost causation for indirect costs.

Guidehouse examined all Cost Drivers for causality and observed that Enbridge where possible, uses Direct Attribution due to its robustness in determining cost causality. For costs that could not be reasonably allocated using any single Cost Driver, or where 3FF was the most appropriate Cost Driver, 3FF was used.

Using the guidelines of the Prong Two Test and understanding industry best practice use of Cost Drivers, Guidehouse determined that certain costs from two Service Categories, totalling $2,411,305 are not reasonably based on cost causation through the Cost Drivers used.

Table 6-5 Summary of Prong Two Test Adjustments

Central Function	Service Category	Cost Driver	Budgeted Allocation	Adjustment / Exception	Adjustment	Adjustment Rationale
CDO	Investment Review	3FF	$1,616,975	Pass with Adjustment	$808,488	Insufficient evidence of cost causality.
Finance	Tax Services	3FF	$4,818,146	Pass with Adjustment	$1,602,817	Insufficient evidence of cost causality.
Total			**$6,435,121**		**$2,411,305**	

Guidehouse Cost Allocation Findings:

Guidehouse found that $318,787,589 of costs allocated to EGI passed the Prong Two Test and were allocated appropriately. Guidehouse determined certain costs from two Service Categories were not allocated using reasonable Cost Drivers that proxy cost causation effectively and required adjustment.

6.2.3 Prong Three Test Results: Cost Benefit

The allocated costs that passed Prong One and Prong Two ($318,787,589) were carried forward into the Prong Three Test.

The objective of the Prong Three Test is to assess whether the CF benefits to Ontario ratepayers equal or exceed the costs. As part of this test, Guidehouse interviewed both the service providers and recipients of each CF. All service recipients indicated that the services they received met at least one, if not multiple, criteria as set out by Three-Prong Test.

To corroborate interview outcomes, Guidehouse conducted a comparative analysis of certain EGI CF costs with peer utilities to establish a frame of reference for benefits, relative to cost levels with functional areas of the business. The analysis focused on EGI's 2022 and 2024 forecasted costs as they reflect the most up to date data available as compared to comparator forecasts obtained through rate filings and other publicly available data.

Guidehouse did not perform comparative analysis for all CF allocations due to lack of publicly available information. With respect to Benefits, Enbridge indicated that it will conduct an independent benchmarking study of benefits in support of EGI's 2024 rebasing application. To maintain competitiveness in the Ontario market, Enbridge targets the midrange for employee benefits relative to its peer group, which consists of large employers in Ontario.

6.2.3.1 Analysis Approach

Guidehouse's approach to perform a comparative review was as follows:

1) Interviewed EGI personnel to gain an understanding of the cost components of each CF and its Cost Drivers.

2) Determined key characteristics appropriate for selection of comparator gas utilities.

3) Selected CFs for which comparable public data was available.

4) Determined an appropriate Normalization Factor for each CF to ensure CF costs are evaluated based in a common scale and consistent manner for all comparators.

5) Gathered relevant public financial data and performed comparative analysis.

Comparator Selection

Guidehouse assembled an initial list of 59 gas and electric distribution utilities from across Canada and the U.S. A prioritization screening approach was developed to set the basis for the comparative review. A score was assigned to each utility according to the similarity to EGI based on relevant criteria. The criteria for scoring were:

1. Number of customers
2. Annual revenue
3. Total annual gas volume distributed (for gas distributers)
4. Customer base (percent that are residential)

The comparator candidate utilities were ranked according to their similarity score. The prioritized utilities were further screened. The top 20 were selected for further examination to select for likely availability of public information. Guidehouse selected twelve utilities that would most likely have publicly available data for comparison with EGI. Additional consideration was given to ensure some Canadian and Ontario based utilities would be represented. Due to the limited number of comparable gas distribution utilities in Ontario, Guidehouse also considered and included Ontario electric utilities such as Hydro One and Toronto Hydro based on comparability of scale, complexity, and similar regulatory oversight.

Table 6-6 Selected Utilities for Comparative Analysis

EGI Comparator Utilities	
FortisBC Energy Inc.	ATCO Gas Distribution
Pacific Gas and Electric Company	Spire Missouri Inc.
Southwest Gas Corporation	Heritage Gas Limited
Consumers Energy Company	EPCOR Utilities Inc. (Ontario)
Atmos Energy Corporation	Southern California Gas Company
Toronto Hydro	Hydro One

Normalization Factor Determination

Each utility's CF costs are impacted by different business needs, geographic location, market characteristics, and regulatory requirements. To ensure comparable results, CF costs for each comparator were assessed on a common basis by normalizing the costs using what is generally referred to as a "Normalization Factor".

Table 6-7 details the Normalization Factors applied to the functional costs assessed in the comparative analysis.

Table 6-7 Selection and Rationale for Normalization Factors

Central Function	Rationale	Normalization Factor
Finance	Costs are typically driven by activities to ensure costs are incurred and tracked prudently and revenues processed.	Total Operating Cost
Legal	Costs are typically driven by legal and regulatory activities, often to ensure revenue is protected and managed for risk.	Total Revenue
HR	Costs are typically driven by managing and administrating employee-related costs and activities.	Number of Employees
TIS	Costs are typically driven by supporting business activities, tracking costs, managing workflow and related costs, processing transactions, and managing operational data.	Total Operating Cost
REWS	EGI is widely geographically dispersed. The size of the distribution system is used to proxy the relative number of field office locations required to manage the distribution network.	Kilometers of pipe where applicable
Insurance	Costs are typically incurred to offset risk of loss of assets and protect revenue lost in case of risk events.	Total Revenue

Data Gathering and Analysis

Guidehouse performed comparative analysis for CFs with publicly available data. As utilities may not consistently report cost and financial information for O&M categories, Guidehouse applied its professional judgement to interpret financial and operating data and drew conclusions regarding its comparability.

Where applicable, Guidehouse made the following adjustments to the data:

1) Converted costs in USD to CAD with the exchange rate of 1.2535 from the Bank of Canada annual average noon-day rate over a period of one year from 2021.

2) Depending on the year of the data, costs were inflated to 2022 and 2024 using reported annual consumer price index from the U.S. Bureau of Labour Statistics and Statistics Canada.

3) Converted miles of pipeline to kilometers with the factor of 1.60934 where applicable.

6.2.4 Calculation Methodology

Normalization Factors were selected as per Table 6-7 and applied to each CF cost category to determine a normalized unit rate. As an example, the 2022 Forecast Finance CF unit rate of $26,099 was derived by dividing the total CF Finance cost allocated to EGI by EGI's total operating cost. This represents a normalized unit rate of Finance cost per million dollars of total EGI operating costs.

6.2.5 Comparative Analysis Results

Guidehouse did not perform comparative analysis using the 2022 Budget. Instead Guidehouse used the more up to date 2022 and 2024 Forecast data provided by Enbridge. (See section 9.2.1)

Guidehouse Cost Benefit Findings:

Guidehouse determined that the benefits to EGI's Ontario ratepayers equal or exceed the costs and the CF costs allocated are generally comparable to the equivalent functional costs of other similar utilities. Adjustments are not recommended due to this test.

7. Conclusions – 2022 Budget

The adjusted allocated costs are reasonable CF costs to be incurred by a utility with the size and complexity of EGI operating in Ontario and provide synergistic and economies of scale benefits that allow the CFs to provide shared services amongst the enterprise to the benefit of affiliate organizations. The benefits and service levels received were supported by service recipients, and a comparative analysis that concluded the CF allocations generally fall within a normalized cost range when compared to other similar utilities and represent reasonable cost of functional service areas.

Based on our study of the costs allocated to EGI through the CFCAM, Guidehouse concludes that 98.5% ($318,787,589) of the allocated costs in the 2022 Budget are reasonably incurred, are established through Cost Drivers that observe key principles of cost allocation and offer benefits that equal or exceed costs for EGI and its ratepayers. These costs pass the Three-Prong test.

Guidehouse concludes that the CFCAM effectively allocates CF costs as intended, with a level of functional integrity that is understandable, transparent, and repeatable.

8. Observations – 2022 Budget

As part of its assessment, Guidehouse made several observations:

1. The ISA between EI and EGI was last reviewed and updated on January 1, 2019. It would be prudent to update the ISA to reflect the current CFCAM, services and definitions more directly and specifically.

2. Within the financial system, several CF Cost Centres were found to be either unclearly named or misaligned with the nature of the intended costs accruing to them. It was determined that this misalignment was generally due to legacy Cost Centre naming conventions that were not aligned with the changing nature of CFs and services therein in parallel with typical organizational changes.

   Ensuring cost centre naming conventions align with the Service Categories they underpin, and the nature of the services and CF cost allocations will enhance transparency and reduce complexity of review and analysis.

3. Some estimated subcontractor costs associated with a specific innovation project, as well as associated Enbridge personnel costs, are captured in the same Finance Transformation Service Category which utilizes High-Level Time Forecasting for cost allocation. High-Level Time Forecasting is an appropriate proxy for cost causation of Enbridge personnel. However, it is not a strong proxy for cost causation for a forward-looking subcontracted innovation project with no prior history. These costs are justifiable expenses for an organization such as EGI, however provide a challenge to measure on a forecast basis. An alternate allocator such as 3FF would have resulted in a higher allocation to EGI, and as such, was not used in this instance. Establishing a separate Service Category for innovation projects would enable the application of a more appropriate Cost Driver.

4. The description for LP Application Management & Support Service Category should be updated to exclude "LP" from its name as the Service Category provides service to the whole enterprise.

5. Some allocation factors were found to be developed and calculated exogenously from the rest of the CFCAM model and applied as inputs. Exogenously calculated and recorded factors create opportunity for transcription and human error.

   Further implementation of automated and embedded allocation factors will enhance the CFCAM and deliver greater integrity.

Guidehouse 2022 Budget Conclusion:

The CFCAM delivers reasonable cost allocation that observes the tenets and principles of the OEB's ARC and aligns to common industry practice.

Overall, total CF costs of $318,787,589 pass the Three-Prong Test. This represents approximately 98.5% of total CF costs comprised of Direct Charge, Directly Attributable, and Indirect costs.

9. 2022 & 2024 Forecasts CFCAM Review Summary

Subsequent to its review of the 2022 Budget, Guidehouse reviewed the allocated costs for 2022 and 2024 Forecasts to determine if the CFCAM continued to be consistent with the 2022 Budget in principle and execution and is applied as intended. The 2024 Forecast represents updated cost projections from the 2022 Forecast and is escalated to 2024 dollars as compared to 2022 Budget.

9.1 Guidehouse Approach and Methodology

Guidehouse reviewed the 2022 and 2024 Forecasts to assess any changes to the model, incremental to those recommended by Guidehouse during its review of the 2022 Budget to ensure the veracity of the CFCAM as applied to the 2022 and 2024 Forecasts.

As part of the review Guidehouse considered any changes in CFs, Service Categories or Cost Drivers other than those recommended by Guidehouse as part of the 2022 Budget assessment. Guidehouse also performed Comparative Analysis for the 2022 and 2024 Forecast costs to ensure the benefits received by EGI are comparable to peer utilities.

9.2 Findings and Results

Guidehouse's assessment of the 2022 and 2024 Forecast cost allocations found that they were based on the 2022B approach with no material changes to the application of the CFCAM or its core tenets. Guidehouse concluded that the CFCAM continued to be in alignment to the principles of the OEB's Three-Prong Test and costs were prudently incurred. Cost allocations continue to be derived through reasonable Cost Drivers that proxy cost causation effectively and that the services provide benefits that were equal or exceeding the costs.

Guidehouse's assessment did not result in any incremental adjustments to the 2022 and 2024 Forecasts. Details of the 2022 and 2024 Forecast cost allocations of each CF is shown in Table 9-1 below.

Table 9-1 2022 and 2024 CF Allocations Forecast[15]

	2022 Forecast				2024 Forecast			
Central Function	**Direct Charge**	**Directly Attributable**	**Indirect Costs**	**Total**	**Direct Charge**	**Directly Attributable**	**Indirect Costs**	**Total**
Aviation	-	11,856	-	11,856	-	12,408	-	12,408
CDO	-	296,005	2,089,494	2,385,499	-	309,777	2,186,714	2,496,491
EAWM	-	-	1,797,397	1,797,397	-	-	1,881,027	1,881,027
Executive	-	-	1,065,704	1,065,704	-	-	1,115,289	1,115,289
Finance	1,187,615	25,035,052	8,823,551	35,046,218	1,242,872	26,199,883	9,234,094	36,676,849
REWS	-	27,430,604	-	27,430,604	-	28,706,895	-	28,706,895
HR	-	24,738,457	-	24,738,457	-	25,889,488	-	25,889,488
Legal	2,947,176	2,786,256	8,923,899	14,657,332	3,084,302	2,915,895	9,339,111	15,339,308
PAC	683,330	5,619,117	-	6,302,446	715,124	5,880,563	33,200	6,628,886
S&R	-	7,206,187	-	7,206,187	-	7,541,476	-	7,541,476
SCM	-	11,675,943	-	11,675,943	-	12,219,202	-	12,219,202
TIS	-	49,018,813	59,323,374	108,342,188	-	77,571,601	62,083,572	139,655,173
Benefits	-	6,832,404	53,505,183	60,337,587	-	5,410,877	55,982,562	61,393,439
Depreciation	-	-	19,996,586	19,996,586	-	-	25,557,831	25,557,831
Insurance	-	15,716,694	-	15,716,694	-	7,328,596		7,328,596
Total	**$ 4,818,121**	**$ 176,367,388**	**$ 155,525,189**	**$ 336,710,698**	**$ 5,042,298**	**$ 199,986,660**	**$ 167,413,398**	**$ 372,442,357**

[15] See table 6-2 for 2022 Budget Comparison

9.2.1 2022 Forecast Findings

The 2022 Forecast presents updated cost projections as compared to the 2022 Budget. Guidehouse's assessment found the CFCAM and the 2022 Forecast costs to be similar in nature to the 2022 Budget. Allocated costs are effectively in alignment from the budgetary perspective, the costs observed the tenets of reasonable cost allocations and continue to provide benefits that equaled or exceeded the costs.

Comparative Analysis Results

Guidehouse's comparative analysis for the 2022 Forecast indicates the costs allocated to EGI from the selected Central Functions, and Insurance fall either below or within the comparative utility range. As a result, Guidehouse does not recommend any adjustment to a specific functional area or to the overall cost allocation.

Table 9-2 2022 Forecast Comparative Analysis

Central Function	Normalizing Factor	EGI	Comparative Utilities			Assessment
			Min	Average	Max	
Finance	$M Total Operating Cost	$23,951	$13,166	$22,846	$39,050	Within Range
Legal	$M Revenue	$7,150	$8,705	$13,690	$25,089	Below Range
HR	# Employees	$7,643	$2,527	$8,537	$18,532	Within Range
TIS	$M Total Operating Cost	$61,319	$26,764	$44,162	$73,643	Within Range
REWS	KM of Pipeline	$184	$57	$879	$3,138	Within Range
Insurance	$M Revenue	$5,788	$1,026	$13,442	$23,610	Within Range

9.2.2 2024 Forecast Findings

The 2024 Forecast presents escalated cost estimates, as well as known updated costs projections[16] as compared to the 2022 Forecast. Guidehouse's assessment found that the 2024 Forecast costs continued to be in alignment with the intent of the CFCAM and are fair and reasonable. The cost allocation observes the tenets of reasonable cost allocations and provides benefits that equaled or exceeded the cost.

Comparative Analysis Results

Guidehouse's comparative analysis for 2024 Forecast indicates that the costs allocated to EGI from the selected Central Functions, and Insurance fall below or within the comparative utility range. Guidehouse does not recommend any adjustments.

[16] For example, implementation costs related to TIS investments as detailed in EGI's Asset Management Plan.

Table 9-3 2024 Forecast Summary of Utility Comparative Analysis

Central Function	Normalizing Factor	EGI	Comparative Utilities			Assessment
			Min	Average	Max	
Finance	$M Total Operating Cost	$21,759	$11,812	$23,296	$43,830	Within Range
Legal	$M Revenue	$6,477	$8,072	$13,413	$25,886	Below Range
HR	# Employees	$7,748	$2,932	$8,572	$19,703	Within Range
TIS	$M Total Operating Cost	$67,114	$29,815	$45,911	$69,610	Within Range
REWS	KM of Pipeline	$189	$59	$844	$2,652	Within Range
Insurance	$M Revenue	$2,352	$1,026	$12,815	$23,610	Within Range

Guidehouse 2022 and 2024 Forecasts Conclusion

Overall, 2022 CF cost allocation Forecast of $366,710,698 and 2024 CF cost allocation Forecast of $372,442,357 pass the OEB's Three-Prong Test. Adjustments are not recommended.

The CFCAM for the 2022 and 2024 Forecasts continues to deliver reasonable cost allocations and observe tenets and principles of the OEB's ARC and align to common industry practice.

Appendix A. Summary Analysis of 2022 Budget by Central Function

Table A-1 Summary Analysis Aviation

<table>
<tr><th colspan="2">Central Function: Aviation</th></tr>
<tr><td>Service Categories</td><td>Business Travel, Pipeline Patrolling</td></tr>
<tr><td>Service Description</td><td>Provide professional and efficient air service in response to company needs, and to conduct operations to the highest safety standards.
Provide pipeline patrolling surveillance over pipelines.</td></tr>
<tr><td>Central Functions Cost Allocation per 2022 Budget</td><td><table><tr><th>Direct Charge</th><th>Directly Attributable</th><th>Indirect</th><th>Total</th><th>Adjustments</th><th>Allocation After Adjustment</th></tr><tr><td>A</td><td>B</td><td>C</td><td>D = A + B + C</td><td>E</td><td>F = D - E</td></tr><tr><td>$ -</td><td>$ 11,288</td><td>$ 2,248,940</td><td>$ 2,260,228</td><td>$ 2,248,940</td><td>$ 11,288</td></tr></table></td></tr>
<tr><td>Prong One Test
Determine if charges to EGI are prudently incurred.
Pass With Adjustment</td><td>Using the corporate jet for executive business travel is unnecessary for a stand-alone utility in Ontario. An adjustment of $2,248,940 has been made to exclude this allocation.

The remaining cost of $11,288 to patrol pipeline, right-of-way, and emergency response is reasonable and required by a stand-alone utility.</td></tr>
<tr><td>Prong Two Test
Determine if charges to EGI are appropriately allocated.
Pass</td><td>Flying Hours is an appropriate Cost Driver to patrol pipelines as the cost of the service is heavily impacted by the number of hours flown.

No adjustments recommended.</td></tr>
<tr><td>Prong Three Test
Determine if the benefits to ratepayers exceed the cost.
Pass</td><td>Adjusted Aviation CF services deliver benefits relative to cost for EGI customers. Pipeline patrol a necessary service for safe transport and operation of gas pipelines.

No adjustments recommended.</td></tr>
<tr><td>Guidehouse Conclusions</td><td>Prong One Passes with an Adjustment of $2,248,940.
Prongs Two and Three Pass.</td></tr>
</table>

Table A-2 Summary Analysis CDO

Central Function: CDO	
Service Categories	Strategy, Corporate Development, Investment Review, Investor Relations
Service Description	• Develop and disseminate a Strategic Plan to position the company for sustainable growth and value creation. • Provide analytical decision support to investment decision makers. • Assess and create investment opportunities for growth. • Integrate finance, communication, marketing, and securities law compliance to enable the most effective communication between Enbridge, the financial community, and other constituencies.
Central Functions Cost Allocation per 2022 Budget	See table below
Prong One Test Determine if charges to EGI are prudently incurred. Pass	The services provided by the CDO Central Function are required and within the scope of a stand-alone utility. A stand-alone utility would require Investor Relations, Corporate Strategy & Development, and Investment Review to guide large capital decisions and facilitate risk management analysis and support the utility's strategic planning process. No adjustments recommended.
Prong Two Test Determine if charges to EGI are appropriately allocated. Pass with Adjustment & Observation	3FF is not a strong proxy for Investment Review cost causation. Certain aspects of Investment Review activities are based upon the levels of investment opportunities, as well as the complexity being reviewed at the enterprise level and impacting all affiliates, while others are discrete Investment Review requirements specific to the EGI utility. In the latter case, cost causation is tied to the number of investments being reviewed for which 3FF is not a strongly linked proxy. Based on high-level time forecasting, the Investment Review Service Category cost was adjusted by 50%, for a total of $808,488. Cost Drivers used for all other Service Categories are appropriate.
Prong Three Test Determine if the benefits to ratepayers exceed the cost. Pass	Adjusted CDO services deliver benefits relative to cost for EGI customers. Strategic actions and activities instituted by CDO produce direct value to EGI and its safe, reliable and resilient operations. No adjustments recommended.
Guidehouse Conclusions	Prongs One and Three Pass. Prong Two Passes with an adjustment of $808,488 and observation.

Central Functions Cost Allocation per 2022 Budget:

Direct Charge	Directly Attributable	Indirect	Total	Adjustments	Allocation After Adjustment
A	B	C	D = A + B + C	E	F = D - E
$ -	$ 430,503	$ 2,731,839	$ 3,162,342	$ 808,488	$ 2,353,854

Table A-3 Summary Analysis EAWM

<table>
<tr><th colspan="2">Central Function: EAWM</th></tr>
<tr><td>Service Category</td><td>Enterprise Asset and Work Management</td></tr>
<tr><td>Service Description</td><td>Manage the lifecycle of physical assets and equipment in order to maximize its lifetime, reduce costs, improve quality and efficiency, health of assets and environmental safety.
Develop and implement advanced work management capabilities to deliver work in a more effective and efficient manner.</td></tr>
<tr><td>Central Functions Cost Allocation per 2022 Budget</td><td><table><tr><th>Direct Charge</th><th>Directly Attributable</th><th>Indirect</th><th>Total</th><th>Adjustments</th><th>Allocation After Adjustment</th></tr><tr><td>A</td><td>B</td><td>C</td><td>D = A + B + C</td><td>E</td><td>F = D - E</td></tr><tr><td>$ -</td><td>$ -</td><td>$ 1,682,547</td><td>$ 1,682,547</td><td>$ -</td><td>$ 1,682,547</td></tr></table></td></tr>
<tr><td>Prong One Test
Determine if charges to EGI are prudently incurred.
Pass</td><td>Enterprise Asset and Work Management Systems, associated staff, standards, policies, processes, and procedures are prudent for a stand-alone utility such as EGI. Enterprise Asset Management provides a systematic approach to the governance and realization of value from EGI's assets over their whole life cycles while Enterprise Work Management improves EGI's productivity in business processes or projects.

No adjustments recommended.</td></tr>
<tr><td>Prong Two Test
Determine if charges to EGI are appropriately allocated.
Pass</td><td>3FF is a good proxy for cost causality given enterprise resources are consumed by and managed on behalf of the utility.

No adjustments recommended.</td></tr>
<tr><td>Prong Three Test
Determine if the benefits to ratepayers exceed the cost.
Pass</td><td>EAWM is a widely used enterprise concept to ensure prudent resource use and risk-management decision making. EAWM delivers benefits relative to cost for EGI customers by reducing fixed investment and maintenance costs of EAWM resources at the affiliate level.

No adjustments recommended.</td></tr>
<tr><td>Guidehouse Conclusions</td><td>Prongs One, Two and Three Pass.</td></tr>
</table>

Table A-4 Summary Analysis Executive

Central Function: Executive	
Service Category	Executive
Service Description	• Make major corporate decisions, manage operations and Central Functions, and overall resources. • Provides strategic and executive leadership over all EI companies including EGI. • Liaison between EI and the investment community to improve access to capital markets and funding to support EGI's operations and approved capital structure. • Act as the main point of communication between the Board of Directors and corporate operations.
Central Functions Cost Allocation per 2022 Budget	Direct Charge (A): $ - ; Directly Attributable (B): $ - ; Indirect (C): $ 1,041,258 ; Total (D = A + B + C): $ 1,041,258 ; Adjustments (E): $ - ; Allocation After Adjustment (F = D - E): $ 1,041,258
Prong One Test Determine if charges to EGI are prudently incurred Pass	EI's complex organizational and financial structure requires several layers of executive management. These layers are not duplicative and derive benefits for EGI. Parent company executive costs are related to reasonable service, governance, risk management and investment oversight that improves operational and policy decisions of EGI which EGI would otherwise require. No adjustments recommended.
Prong Two Test Determine if charges to EGI are appropriately allocated. Pass	Using 3FF to allocate the Executive Central Function is appropriate as it benefits the entire enterprise. No adjustments recommended.
Prong Three Test Determine if the benefits to ratepayers exceed the cost. Pass	The Office of the CEO as a Central Function provides benefits such as governance, liaison between EI and investment community to improve access to capital markets, and oversight of EGI. Executive services costs are found to deliver benefits relative to cost for EGI customers. No adjustments recommended.
Guidehouse Conclusions	Prongs One, Two and Three Pass.

Table A-5 Summary Analysis Finance

Central Function: Finance	
Service Categories	Gas Distribution Finance, General Finance, Management Reporting, Planning and Budgeting, External Reporting, Accounts Payable, Capital Asset Accounting and Reporting, Treasury, Credit, Tax Services, Audit Services, Risk Assessment, Risk Control and Contracts, Accounting Policy and Internal Controls, Finance Transformation
Service Description	• Provide information on actual and future financial performance, partner in decision making, and manage finance operations for the enterprise in addition to EGI specifically. • Execute transactional accounting processes including invoice processing and management of capital asset reporting. • Execute capital, credit, tax, audit and risk assessment and control programs. • Maintain control environment and accounting policies. • Support strategic and practical initiatives within the Finance function.
Central Functions Cost Allocation per 2022 Budget	(see table below)
Prong One Test Determine if charges to EGI are prudently incurred. Pass	Finance Central Function is required and within the scope of a stand-alone utility. A stand-alone utility would require accurate financial information to monitor its performance, support its decision making, develop strategies and communicate its operational and financial performance to the investor community. No adjustments recommended.
Prong Two Test Determine if charges to EGI are appropriately allocated. Pass With Adjustment	**Tax Services Service Category** - 3FF is not a strong proxy for causation for income tax service costs resulting from US tax services. This service was adjusted by $1,602,817 to reflect the level of effort for US Tax Services. The cost driver was subsequently updated to high-level time forecasting in the 2022 Forecast; therefore no further adjustment is required in relation to the 2022 Forecast. The Cost Drivers for the remaining Service Categories are appropriate.
Prong Three Test Determine if the benefits to ratepayers exceed the cost. Pass	Adjusted Finance services deliver benefits relative to cost for EGI customers. The Finance Central Function creates efficiencies as a pool of experts provide a wide variety financial expertise including specialized expertise such as Debt Issuance across all affiliates creating direct value to Ontario ratepayers. 2022 and 2024 Forecast Finance costs fall within the comparative utility range. No adjustments recommended.
Guidehouse Conclusions	Prongs One and Three Pass. Prong Two Passes with an adjustment of $1,602,817.

Central Functions Cost Allocation per 2022 Budget:

Direct Charge	Directly Attributable	Indirect	Total	Adjustments	Allocation After Adjustment
A	B	C	D = A + B + C	E	F = D - E
$ 1,460,819	$ 24,784,765	$ 9,036,439	$ 35,282,023	$ 1,602,817	$ 33,679,206

Table A-6 Summary Analysis REWS

<table>
<tr><th colspan="2">Central Function: REWS</th></tr>
<tr><td>Service Categories</td><td>Real Estate (various locations), Real Estate (General)</td></tr>
<tr><td>Service Description</td><td>Provide a cost-effective workplace that enables the business to achieve its strategic objectives.</td></tr>
<tr><td>Central Functions Cost Allocation per 2022 Budget</td><td>
<table>
<tr><th>Direct Charge</th><th>Directly Attributable</th><th>Indirect</th><th>Total</th><th>Adjustments</th><th>Allocation After Adjustment</th></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D = A + B + C</td><td>E</td><td>F = D - E</td></tr>
<tr><td>$ -</td><td>$ 28,098,028</td><td>$ -</td><td>$ 28,098,028</td><td>$ -</td><td>$ 28,098,028</td></tr>
</table>
</td></tr>
<tr><td>Prong One Test
Determine if charges to EGI are prudently incurred.
Pass</td><td>The REWS CF is required and within the scope of a stand-alone utility. EGI requires facility costs and REWS staff to operate workplaces, facilitate the management of real estate assets and provide a safe workplace and functional amenities to its employees.

No adjustments recommended.</td></tr>
<tr><td>Prong Two Test
Determine if charges to EGI are appropriately allocated.
Pass</td><td>Capacity Utilization of a location by EGI employees is an appropriate causation for allocation of Real Estate Services costs for specified locations.

High-Level Time Forecasting to proxy for the costs of REWs function employees who provide oversight and support to corporate and affiliate assets is appropriate. All REWS allocations are Directly Attributable indicating strong causality.

No adjustments recommended.</td></tr>
<tr><td>Prong Three Test
Determine if the benefits to ratepayers exceed the cost.
Pass</td><td>REWS services deliver benefits relative to cost for EGI customers. REWS CF costs are incurred to maintain offices that support customers and Enbridge Gas' operations across Ontario.

2022 and 2024 Forecast REWS costs fall within the comparative utility range.

No adjustments recommended.</td></tr>
<tr><td>Guidehouse Conclusions</td><td>Prongs One, Two and Three Pass.</td></tr>
</table>

Table A-7 Summary Analysis HR

<table>
<tr><th colspan="2">Central Function: HR</th></tr>
<tr><td>Service Categories</td><td>Advisory Service and Recruitment, Payroll and MyHR, HR Business Partners, Rewards and Analytics
Benefits and Pension Administration, Health Services, Operational Performance and Quality Assurance
Talent Management, Enterprise Cost</td></tr>
<tr><td>Service Description</td><td>• Provide advisory support for leader and employee relations and recruitment.
• Provide support for payroll, compensation, and benefits programs.
• Execution of talent management programs.</td></tr>
<tr><td>Central Functions Cost Allocation per 2022 Budget</td><td><table><tr><th>Direct Charge</th><th>Directly Attributable</th><th>Indirect</th><th>Total</th><th>Adjustments</th><th>Allocation After Adjustment</th></tr><tr><td>A</td><td>B</td><td>C</td><td>D = A + B + C</td><td>E</td><td>F = D - E</td></tr><tr><td>$ -</td><td>$ 22,890,498</td><td>$ -</td><td>$ 22,890,498</td><td>$ -</td><td>$ 22,890,498</td></tr></table></td></tr>
<tr><td>Prong One Test
Determine if charges to EGI are prudently incurred.
Pass</td><td>HR CF is required and within the scope of a stand-alone utility. A stand-alone utility would require HR services to develop HR policies, provide recruitment guidance, talent management, compensation planning and delivery, and ensure employees are provided developmental programs to foster growth, as well as an inclusive and diverse culture.

No adjustments recommended.</td></tr>
<tr><td>Prong Two Test
Determine if charges to EGI are appropriately allocated.
Pass</td><td>HR Case Volume, Estimated Salary, and HR Business Partners Headcount are appropriate Cost Drivers for HR Service Categories and are strong proxies for cost causation. All HR allocations are Directly Attributable indicating strong causality.

No adjustments recommended.</td></tr>
<tr><td>Prong Three Test
Determine if the benefits to ratepayers exceed the cost.
Pass</td><td>HR services deliver benefits relative to cost for EGI customers. HR CF provides synergistic and economies of scale benefits that allow Enbridge to provide shared services amongst the enterprise at a lower cost, as well as alignment of strategy and approach. Savings are achieved as a result of shared HR staff with specialized expertise and third-party services.

2022 and 2024 Forecast HR costs fall within the range of comparative utilities.

No adjustments recommended.</td></tr>
<tr><td>Guidehouse Conclusions</td><td>Prongs One, Two and Three Pass.</td></tr>
</table>

Table A-8 Summary Analysis Legal

Central Function: Legal	
Service Categories	Gas Utilities Law, Ethics and Compliance, TIS and SCM Legal Services, Corporate Law Services, Corporate Secretary Services
Service Description	Provide comprehensive legal services to support corporate, commercial, litigation, regulatory and other business working with external counsel as necessary.
Central Functions Cost Allocation per 2022 Budget	Direct Charge (A): $ 2,802,354; Directly Attributable (B): $ 3,384,958; Indirect (C): $ 8,109,619; Total (D = A + B + C): $ 14,296,931; Adjustments (E): $ -; Allocation After Adjustment (F = D - E): $ 14,296,931
Prong One Test Determine if charges to EGI are prudently incurred. Pass	Legal Function is required and within the scope of a stand-alone utility. A stand-alone utility would require Legal support for corporate secretarial, contracting, litigations, as well as ethics and compliance to promote EGI's culture of compliance. Legal also provides specialized Indigenous law services that is needed by EGI and is shared amongst Enbridge's affiliates. No adjustments recommended.
Prong Two Test Determine if charges to EGI are appropriately allocated. Pass	High-Level Time Forecasting is an appropriate Cost Driver for Corporate Law, Gas Utilities Law, and GTM and LP Law Service Categories as these provide on demand services for the LOBs. 3FF is an appropriate Cost Driver for Corporate Secretarial, TIS, SCM Legal Services as well as Ethics, Compliance, Privacy & Security as these services benefit the entire organization. No adjustments recommended.
Prong Three Test Determine if the benefits to ratepayers exceed the cost. Pass	Legal services deliver benefits relative to cost for EGI customers. Legal CF provides synergistic and economies of scale benefits that allow Enbridge to provide shared services amongst the enterprise at a lower price, as well as alignment of strategy and approach. Savings are achieved as a result of shared Legal staff with specialized expertise and third-party legal services. 2022 and 2024 Forecast Legal costs fall within the comparative utility range. No adjustments recommended.
Guidehouse Conclusions	Prongs One, Two and Three Pass.

Table A-9 Summary Analysis PAC

Central Function: PAC	
Service Categories	Enterprise Communications, Corporate Social Responsibility and Community Investment, External Affairs and Policy Stakeholder & Indigenous Engagement, Public Awareness
Service Description	• Engagement strategies that support the business objectives including Enterprise Communications, Corporate Social Responsibility, community investment governance and industry relations. • Strategic advocacy in support of projects, operations and public policy including public awareness outreach, stakeholder and Indigenous engagement and external affairs.
Central Functions Cost Allocation per 2022 Budget	(see table below)
Prong One Test Determine if charges to EGI are prudently incurred. Pass	PAC services are required and within the scope of a stand-alone utility. A stand-alone utility would require government relations, branding and communication strategy, Indigenous affairs, community relations, philanthropy, as well as sustainability and Environmental, Social and Governance (ESG) reporting. No adjustments recommended.
Prong Two Test Determine if charges to EGI are appropriately allocated. Pass	High-Level Time Forecasting and Donations Value are appropriate Cost Drivers for PAC Service Categories and are good proxies for cost causation. No adjustments recommended.
Prong Three Test Determine if the benefits to ratepayers exceed the cost. Pass	PAC services deliver benefits relative to cost for EGI customers. PAC CF provides synergistic and economies of scale benefits that allow Enbridge to provide shared services amongst the enterprise at a lower price as well as alignment of strategy and approach. No adjustments recommended.
Guidehouse Conclusions	Prongs One, Two and Three Pass.

Central Functions Cost Allocation per 2022 Budget:

Direct Charge	Directly Attributable	Indirect	Total	Adjustments	Allocation After Adjustment
A	B	C	D = A + B + C	E	F = D - E
$ 635,000	$ 5,155,876	$ -	$ 5,790,876	$ -	$ 5,790,876

Table A-10 Summary Analysis S&R

<table>
<tr><th colspan="2">Central Function: S&R</th></tr>
<tr><td>Service Categories</td><td>Safety, Centres of Excellence</td></tr>
<tr><td>Service Description</td><td>Supports safety training, safety consulting services, regulation, and contractor programs.
Provides support for Risk, Management, and Governance within Enterprise Safety and Operational Reliability.</td></tr>
<tr><td>Central Functions Cost Allocation per 2022 Budget</td><td><table><tr><th>Direct Charge</th><th>Directly Attributable</th><th>Indirect</th><th>Total</th><th>Adjustments</th><th>Allocation After Adjustment</th></tr><tr><td>A</td><td>B</td><td>C</td><td>D = A + B + C</td><td>E</td><td>F = D - E</td></tr><tr><td>$ -</td><td>$ 7,062,208</td><td>$ -</td><td>$ 7,062,208</td><td>$ -</td><td>$ 7,062,208</td></tr></table></td></tr>
<tr><td>Prong One Test
Determine if charges to EGI are prudently incurred.
Pass</td><td>S&R services are required and within the scope of a stand-alone utility. A stand-alone utility would require Safety and Reliability services to develop and manage safety management programs, monitor, and report on performance, provide emergency management and take corrective action.

No adjustments recommended.</td></tr>
<tr><td>Prong Two Test
Determine if charges to EGI are appropriately allocated.
Pass</td><td>High-Level Time Forecasting and Estimated Salary for S&R Service Categories are good proxies for cost causation. All S&R allocations are Directly Attributable indicating strong causality.

No adjustments recommended.</td></tr>
<tr><td>Prong Three Test
Determine if the benefits to ratepayers exceed the cost.
Pass</td><td>S&R services deliver benefits relative to cost for EGI customers. S&R CF provides synergistic and economies of scale benefits that allow Enbridge to provide shared services amongst the enterprise at a lower price. S&R provides specialized expertise that supports the entire enterprise in delivering robust safety measures, increased reliability of service and emergency response.

No adjustments recommended.</td></tr>
<tr><td>Guidehouse Conclusions</td><td>Prongs One, Two and Three Pass.</td></tr>
</table>

Table A-11 Summary Analysis SCM

<table>
<tr><th colspan="2">Central Function: SCM</th></tr>
<tr><td>Service Categories</td><td>Gas Distribution Operations, Materials Management and Logistics, Direct Category Management, Indirect Category Management, Planning, Governance and Technology</td></tr>
<tr><td>Service Description</td><td>1. Primary point of contact for internal customers.
2. Manage supply chain planning and supply chain execution.
3. Define, recommend, and execute category strategies for key categories of direct and indirect goods and services.</td></tr>
<tr><td>Central Functions Cost Allocation per 2022 Budget</td><td>
<table>
<tr><th>Direct Charge</th><th>Directly Attributable</th><th>Indirect</th><th>Total</th><th>Adjustments</th><th>Allocation After Adjustment</th></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D = A + B + C</td><td>E</td><td>F = D - E</td></tr>
<tr><td>$ -</td><td>$ 7,771,386</td><td>$ -</td><td>$ 7,771,386</td><td>$ -</td><td>$ 7,771,386</td></tr>
</table>
</td></tr>
<tr><td>Prong One Test
Determine if charges to EGI are prudently incurred.
Pass</td><td>SCM services are required and within the scope of a stand-alone utility. SCM CF staff are embedded within the utility to support EGI's supply chain needs including governance, procurement and enterprise agreements. A stand-alone utility would require supplier sourcing, supplier relationship management, material management and warehousing.

No adjustments recommended.</td></tr>
<tr><td>Prong Two Test
Determine if charges to EGI are appropriately allocated.
Pass</td><td>EGI uses SCM CF when needed. All SCM allocations are Directly Attributable indicating strong causality and a good proxy for causation.

No adjustments recommended.</td></tr>
<tr><td>Prong Three Test
Determine if the benefits to ratepayers exceed the cost.
Pass</td><td>SCM services deliver benefits relative to cost for EGI customers. SCM CF provides synergistic and economies of scale benefits that allow Enbridge to provide shared services amongst the enterprise at a lower price. SCM CF provides specialized expertise that supports the entire enterprise in selecting vendors, negotiating contracts, and processing purchase orders.

No adjustments recommended.</td></tr>
<tr><td>Guidehouse Conclusions</td><td>Prongs One, Two and Three Pass.</td></tr>
</table>

Table A-12 Summary Analysis TIS

<table>
<tr><th colspan="2">Central Function: TIS</th></tr>
<tr><td>Service Categories</td><td>Gas Distribution Application Management and Support, Enterprise Application and Management Support, Core Infrastructure Operations, Gas Distribution Operational Technology, Cyber Security, IT Service Management and Client Services, Network Services, Mobility, Technology Direction and Governance</td></tr>
<tr><td>Service Description</td><td>Manage the systems and applications that support the whole enterprise in addition to EGI.
Various TIS-related services including core infrastructure operations, operational technology, cyber security, IT service management and client services, network services, mobility, and technology direction and governance.</td></tr>
<tr><td>Central Functions Cost Allocation per 2022 Budget</td><td><table><tr><th>Direct Charge</th><th>Directly Attributable</th><th>Indirect</th><th>Total</th><th>Adjustments</th><th>Allocation After Adjustment</th></tr><tr><td>A</td><td>B</td><td>C</td><td>D = A + B + C</td><td>E</td><td>F = D - E</td></tr><tr><td>$ -</td><td>$ 55,186,406</td><td>$ 45,990,773</td><td>$ 101,177,179</td><td>$ -</td><td>$ 101,177,179</td></tr></table></td></tr>
<tr><td>Prong One Test
Determine if charges to EGI are prudently incurred.
Pass</td><td>TIS are required and within the scope of a stand-alone utility. A stand-alone utility would require network infrastructure, applications, and support for them, as well as cyber security support. TIS ensures continuous improvement, governance, and strategic alignment amongst the enterprise.

No adjustments recommended.</td></tr>
<tr><td>Prong Two Test
Determine if charges to EGI are appropriately allocated.
Pass With Observation</td><td>Over 50% of the charges in this CF are Directly Attributable indicating strong causality. 3FF and network circuit usage are good proxies for cost causation.

LP Application Management & Support Service Category: costs benefit EGI and allocations to EGI from this Service Category are appropriate. A stand-alone utility would require application support management services for managing the resolution of application and system issues that arise across the business.

Observation: The description for the Cost Driver should exclude "LP" from its name as Service Category provides service to the whole enterprise.

No adjustments recommended.</td></tr>
<tr><td>Prong Three Test
Determine if the benefits to ratepayers exceed the cost.
Pass</td><td>TIS CF delivers benefits relative to cost for EGI customers. TIS CF provides synergistic and economies of scale benefits that allow Enbridge to provide shared services amongst the enterprise at a lower price, as well as alignment of strategy and approach. TIS provides specialized expertise that supports the entire enterprise in delivering a robust and secure IT infrastructure.

2022 and 2024 Forecast TIS costs fall within the comparative utility range.

No adjustments recommended.</td></tr>
<tr><td>Guidehouse Conclusions</td><td>Prongs One, and Three Pass.
Prong Two passes with observation.</td></tr>
</table>

Table A-13 Summary Analysis Benefits

Central Function: Benefits	
Description	Pension, long-term incentive, health, and other benefit costs.
Central Functions Cost Allocation per 2022 Budget	Direct Charge (A): $ - ; Directly Attributable (B): $ 6,700,727 ; Indirect (C): $ 44,769,432 ; Total (D = A + B + C): $ 51,470,159 ; Adjustments (E): $ - ; Allocation After Adjustment (F = D - E): $ 51,470,159
Prong One Test Determine if charges to EGI are prudently incurred. Pass	Competitive benefits are a key tenet in attracting and maintaining appropriate talent for EGI and are prudent. Employee benefits are required and within the scope of a stand-alone utility. No adjustments recommended.
Prong Two Test Determine if charges to EGI are appropriately allocated. Pass	Directly Attributable Cost Driver for Benefits including Pension and Long-Term Incentive Plan (LTIP) for EGI employees is appropriate and provides strong causal relationship. 3FF Cost Driver for Benefits including Pension and Long-Term Incentive Plan (LTIP) for non-EGI CF employees that provide service to EGI is appropriate. No adjustments recommended.
Prong Three Test Determine if the benefits to ratepayers exceed the cost. Pass	Centrally acquired and administered benefits provide economies of scale and efficiencies for the entire enterprise and deliver benefits relative to cost for EGI customers. Enbridge indicated that it will conduct an independent benchmarking study of benefits in support of EGI's 2024 rebasing application. Enbridge targets the midrange relative to its peer group, which consists of large employers in Ontario. No adjustments recommended.
Guidehouse Conclusions	Prongs One, Two and Three Pass.

Direct Charge	Directly Attributable	Indirect	Total	Adjustments	Allocation After Adjustment
A	B	C	D = A + B + C	E	F = D - E
$ -	$ 6,700,727	$ 44,769,432	$ 51,470,159	$ -	$ 51,470,159

Table A-14 Summary Analysis Depreciation

<table>
<tr><th colspan="2">Central Function: Depreciation</th></tr>
<tr><td>Description</td><td>The cost of shared assets that provide benefit to the entire enterprise are allocated to LOBs as depreciation.</td></tr>
<tr><td>Central Functions Cost Allocation per 2022 Budget</td><td><table>
<tr><th>Direct Charge</th><th>Directly Attributable</th><th>Indirect</th><th>Total</th><th>Adjustments</th><th>Allocation After Adjustment</th></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D = A + B + C</td><td>E</td><td>F = D - E</td></tr>
<tr><td>$ -</td><td>$ -</td><td>$ 19,682,281</td><td>$ 19,682,281</td><td>$ 268,792</td><td>$ 19,413,489</td></tr>
</table></td></tr>
<tr><td>Prong One Test
Determine if charges to EGI are prudently incurred.
Pass With Adjustment</td><td>Depreciation costs are prudent as they are a function of capital investment in shared resources such as IT systems and real estate which benefits EGI.

A portion of Aviation CF allocation was deemed not prudent. Usage of a corporate jet for business travel is unnecessary for a utility solely based in Ontario. An adjustment to the allocation of depreciation on the corporate jet for $129,930 was made.

Depreciation related to certain IT assets not providing benefits to EGI resulted in an adjustment of $138,863.

The remaining depreciation costs are reasonable and required by a stand-alone utility.</td></tr>
<tr><td>Prong Two Test
Determine if charges to EGI are appropriately allocated.
Pass</td><td>3FF is a good proxy for cost causality as the associated assets benefit the entire enterprise.

No adjustments recommended.</td></tr>
<tr><td>Prong Three Test
Determine if the benefits to ratepayers exceed the cost.
Pass</td><td>Adjusted depreciation costs deliver benefits relative to cost for EGI customers. Centralized shared investments provide economies of scale supporting the entire enterprise. Savings can be expected from economies of scale when investing in assets such as software infrastructure and office buildings that serve multiple affiliates.

No adjustments recommended.</td></tr>
<tr><td>Guidehouse Conclusions</td><td>Prongs Two and Three Pass.
Prong One passes with an adjustment of $268,792.</td></tr>
</table>

Table A-15 Summary Analysis Insurance

Central Function: Insurance	
Description	Represents insurance premiums.
Central Functions Cost Allocation per 2022 Budget	Direct Charge (A): $ - ; Directly Attributable (B): $ 22,048,681 ; Indirect (C): $ - ; Total (D = A + B + C): $ 22,048,681 ; Adjustments (E): $ - ; Allocation After Adjustment (F = D - E): $ 22,048,681
Prong One Test Determine if charges to EGI are prudently incurred. Pass	Insurance services are required and within the scope of a stand-alone utility. A stand-alone utility would require Insurance to manage risks associated with operating a utility. No adjustments recommended.
Prong Two Test Determine if charges to EGI are appropriately allocated. Pass	To allocate insurance costs, Enbridge uses operational data and metrics that are used by insurance underwriters to determine insurance premiums. This is appropriate and a good proxy for causation. No adjustments recommended.
Prong Three Test Determine if the benefits to ratepayers exceed the cost. Pass	Insurance costs deliver benefits relative to cost for EGI customers. Centrally acquired insurance provides economies of scale and efficiencies for the entire enterprise. 2022 and 2024 Forecast Insurance costs fall within the comparative utility range. No adjustments recommended.
Guidehouse Conclusions	Prongs One, Two and Three Pass.

Central Functions Cost Allocation per 2022 Budget:

Direct Charge	Directly Attributable	Indirect	Total	Adjustments	Allocation After Adjustment
A	B	C	D = A + B + C	E	F = D - E
$ -	$ 22,048,681	$ -	$ 22,048,681	$ -	$ 22,048,681

Appendix B. CFCAM

Allocation Methodology Applied to the Allocable Cost Pool

ENBRIDGE Life Takes Energy

Costs allocated using the following approaches

Approach	Definition	Characteristics	Process
Directly Attributable Costs	Centralized Functions costs captured in Cost Centres, which are specifically attributable to a Segment. The costs will be 100% allocated to that Segment and subsequently allocated within the Segment using a Cost Driver	• Cost recipient decided by **Centralized Functions** • Cost sent to **specific LOBs** in that Segment	Centralized Function → Service Category → Specific Segment → LOB 1, LOB 2, LOB 3
Directly Attributable Costs	The CF costs are attributable to multiple Segments. Such cost will be allocated in two steps: first the cost is assigned to individual Segments based on a driver, such as a time estimate, and then the assigned cost is allocated to LOBs within such Segments	• Cost recipients decided by **Centralized Functions** • Cost is first sent to **specific Segments and then to LOBs** in such Segment	Centralized Function → Service Category → Segment 1 → LOB 1; Service Category → Segment 2 → LOB 2, LOB 3
Indirect Cost Allocation	Allocation of costs for services provided by Centralized Functions to the whole enterprise, and not specifically related to a single Segment	• Costs are allocated to the **entire enterprise** using Cost Drivers	Centralized Function → Service Category → LOB 1, LOB 2, LOB 3
Direct Charge Cost	Certain costs residing in Cost Centres mapped directly to operating LOBs will be **excluded from the Allocable Cost Pool** and left as a direct charge to the Segment they roll up to	• Costs are directed to the appropriate **Line of Business** • Affects **Legal, Audit, S&R and PAC** costs that are under **"Direct Charge"**	Line of Business: Cost Centre

– – – – – **In Scope for Cost Allocation methodology**

Appendix C. List of Interview Attendees

Guidehouse conducted 10 interviews with attendees from both service providers and recipients of each CF. The tables below list the interview participants.

Table D-1 Interview Participants - Aviation

Title	Service Provider / Recipient
Manager Aviation	Service Provider
Business Co-Ordinator Aviation	Service Provider

Table D-2 Interview Participants - CDO

Title	Service Provider / Recipient
Manager Strategic Financial Evaluations	Service Recipient
Manager Business Development	Service Recipient
Supervisor Capital Development	Service Recipient
Manager Business Development (Storage & Transmission)	Service Recipient
Manager Strategic Financial Evaluations	Service Recipient
Director, Strategy and Fundamentals	Service Provider
Technical Manager Investment Review	Service Provider
Investment Review Specialist	Service Provider

Table D-3 Interview Participants - Finance

Title	Service Provider / Recipient
Director Accounting GDS	Service Recipient
Director FP&A GDS	Service Recipient
Advisor Shared Services and Consolidations	Service Recipient
Supervisor Finance Applications & Development	Service Recipient
Director Financial Reporting	Service Provider
Director Shared Services	Service Provider
Director Capital Assets, Shared Services	Service Provider
Director & Finance Business Partner Enterprise FP&A	Service Provider

Table D-4 Interview Participants - HR

Title	Service Provider / Recipient
Director HRBP GD & Storage	Service Recipient
Director Talent Management	Service Provider
Director Benefits & Operations	Service Provider
Director Payroll Data and Services	Service Provider
Director Advisory Services	Service Provider
Advisor, HR Budgeting and Planning	Service Provider

Table D-5 Interview Participants - Legal

Title	Service Provider / Recipient
Vice President, Law	Service Recipient
Sr Legal Counsel	Service Recipient
Specialist, Legal Services Finance Optimization	Service Provider
Manager Legal Services Analytics & Financial Optimization	Service Provider

Table D-6 Interview Participants - PAC

Title	Service Provider / Recipient
Director Public Affairs & Ombudsman	Service Recipient
Director External Affairs Canada	Service Provider
Director Corporate Reputation & Strategy	Service Provider

Table D-7 Interview Participants - REWS

Title	Service Provider / Recipient
Specialist II Governance and Planning WPS	Service Recipient
Supervisor Workplace Services	Service Recipient
Specialist I Real Estate Strategy	Service Recipient
Manager Governance and Planning	Service Provider

Table D-8 Interview Participants - S&R

Title	Service Provider / Recipient
Specialist Management Systems	Service Recipient
Manager Safety Enbridge Gas	Service Recipient
Specialist Governance	Service Provider

Table D-9 Interview Participants - SCM

Title	Service Provider / Recipient
Director SCM Gas Distribution & Storage	Service Recipient
Manager SCM Governance & Finance	Service Provider
Sr. Specialist SCM Governance & Finance	Service Provider

Table D-10 Interview Participants - TIS

Title	Service Provider / Recipient
Manager TIS Asset and Performance Management	Service Recipient

INTERCORPORATE SERVICES AGREEMENT

ENBRIDGE INC.

– and –

ENBRIDGE GAS INC.

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INTERCORPORATE SERVICES AGREEMENT

THIS AGREEMENT made as of the 1st day of January, 2019 (the "**Effective Date**")

B E T W E E N:

ENBRIDGE INC., a corporation incorporated under the laws of Canada ("**EI**")

- and -

ENBRIDGE GAS INC., a corporation incorporated under the laws of the Province of Ontario ("**EGI**")

WHEREAS EI and Enbridge Gas Distribution Inc. entered into a prior intercorporate services agreement made as of January 1, 2016 (the "**Prior Agreement**");

AND WHEREAS Enbridge Gas Distribution Inc. and Union Gas Limited amalgamated, effective January 1, 2019, to form EGI;

AND WHEREAS EI and EGI intend to terminate the Prior Agreement and replace it, effective from January 1, 2019 (pursuant to Section 2), with this Agreement which reflects an updated cost allocation methodology;

AND WHEREAS EGI wishes to provide to EI and its Affiliates and EGI wishes to receive from EI and its Affiliates certain services, resources and products set forth in Schedule 1 (the "**Services**");

AND WHEREAS the Parties wish to allocate the costs of the Services in accordance with the terms and conditions of this Agreement;

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and mutual covenants hereinafter contained, the Parties agree:

1. Definitions

"Accounting for Intercompany Transactions Policy" means Enbridge's Accounting for Intercompany Transaction Policy, version 1.0, as may be amended from time to time.

"Affiliate" has the meaning set forth in the Code, provided however that:

(a) in respect of a Service Recipient, "Affiliate" shall not include the Service Provider in respect of the applicable Services and any Affiliate of the Service Provider to whom the Service Provider assigns or delegates the performance of such Services; and

(b) in respect of a Service Provider, "Affiliate" shall not include the Service Recipient in respect of the applicable Services.

"Agreement" means this Intercorporate Services Agreement, including its recitals and schedules annexed hereto or otherwise incorporated herein, as may be amended from time to time.

"Business Day" means a day on which banks are open for normal commercial business and which is not a Saturday or a Sunday or statutory holiday.

"CCAM" has the meaning set forth in Article 4.

"CCAM Report" has the meaning set forth in Section 5.2.

"Code" means the OEB's *Affiliate Relationships Code for Gas Utilities*, as amended from time to time.

"Confidential Customer Information" has the meaning set forth in Section 12.4.

"Disclosing Party" has the meaning set forth in Section 12.1.

"Effective Date" has the meaning set forth in the Preamble.

"EGI" has the meaning set forth in the Preamble.

"EI" has the meaning set forth in the Preamble.

"Indemnified Party" has the meaning set forth in Section 11.3(a).

"Indemnifying Party" has the meaning set forth in Section 11.3(a).

"Insolvency Event" means, in the case of a person, that it: (a) files a voluntary application in or for liquidation, receivership or bankruptcy; (b) is subject to the filing of an involuntary petition for bankruptcy if such petition is not discharged or dismissed within sixty (60) days after such petition was filed; (c) is finally and validly declared and adjudged to be liquidated, bankrupt or insolvent; (d) is subject to a resolution passed by its members for the purposes of placing it in voluntary administration; (e) is subject to an order by any court of competent jurisdiction for its winding up; (f) is the subject of an appointment of a receiver or receiver and manager or like officer of all or substantially all of its assets; (g) has a secured party take possession of all or substantially all its assets or has a distress, execution, attachment, sequestration or other legal process levied or enforced on it or against all or substantially all of its assets; and such secured party maintains possession, or any such process is not dismissed, discharged, stayed or restrained, in each case within fifteen (15) Business Days thereafter; (h) is the subject of an appointment of an administrator, official manager or like officer in circumstances where it is or is likely to become insolvent; or (i) enters into a scheme or plan of arrangement with its creditors or any of them or declares a moratorium on the payment of its creditors, but does not include any voluntary proceeding for the purpose of amalgamation, reconstruction or reorganization not taken at the request of or to meet the requirements of the creditors of such person.

"OEB" means the Ontario Energy Board, including any successors or permitted assigns.

"Parties" means EI and EGI, and "Party" means any one of EI or EGI.

"Personal Information" has the meaning set forth in Section 12.3.

"Prior Agreement" has the meaning set forth in the Recitals.

"Receiving Party" has the meaning set forth in Section 12.1.

"Representative" means any Service Provider Representative and any Service Recipient Representative.

"Senior Supervisory Personnel" means, with respect to a Party, any director or officer of such Party, and any individual who functions for such Party (or one of its Affiliates with responsibility for such Party or any of its business or operating functions) at a management level equivalent or superior to any individual functioning as Vice-President.

"Services" has the meaning set forth in the Recitals.

"Services Charge" means the amount allocated by EI to EGI pursuant to the CCAM. For greater certainty, the Services Charge shall be the aggregate direct and allocated costs of Services received by EGI less the aggregate cost of Services provided by EGI, as further described in Schedule 2.

"Service Provider" means either Party, when providing Services to the other Party.

"Service Provider Representatives" means a Service Provider, such Service Provider's Affiliates, and its and their respective directors, officers, employees, agents and contractors.

"Service Recipient" means either Party, when receiving Services from the other Party.

"Service Recipient Representatives" means a Service Recipient, such Service Recipient's Affiliates, and its and their respective directors, officers, employees, agents and contractors.

"Term" has the meaning set forth in Section 8.1.

"Third Party Claim" has the meaning set forth in Section 11.3.

2. Other Agreements

Effective as of 11:59 pm EST on December 31, 2018, the Prior Agreement is terminated. Effective as of 12:00 am EST on January 1, 2019, this Agreement shall be in full force and effect.

3. Regulatory Considerations

The Parties acknowledge that this Agreement is subject to any rule or order applicable to EGI made by the OEB pursuant to the *Ontario Energy Board Act*, S.O. 1998, c. 15, Sch. B., including without limitation, the Code. EI agrees to do and to cause its Affiliates to do such things as are reasonably necessary to assist EGI in complying with these rules, including without limitation, promptly complying with all requests either made or authorized by the OEB for information with respect to: (a) the Services; and (b) the cost of providing the Services.

4. Central Services Cost Allocation Methodology

EI, in consultation with EGI, has developed a central services cost allocation methodology attached hereto as Schedule 2 (the "**CCAM**"). The CCAM sets out the purpose, objectives, principles, and procedures for identifying and allocating the costs of the Services received and provided by EI and its Affiliates, including EGI. EGI will use the CCAM to determine the amounts which it will request to be recovered in rates from time to time. For clarity, where a section of this Agreement is inconsistent with the CCAM, the CCAM shall prevail.

5. Allocation Procedures

5.1 Cost allocations shall be made in accordance with the processes and procedures set out in the CCAM, which describes how EI will assign direct costs and calculate the allocable portion of pooled allocable costs of the Services to its Affiliates, including EGI.

5.2 EI, in consultation with its Affiliates, including EGI, shall set the projected CCAM cost allocations for the Services prior to December 31st of the year prior to the year to which the cost allocations apply, or as soon thereafter that such budgeting and cost allocation processes are concluded. As soon as practicable following such process, EI shall provide an annual CCAM report to each Affiliate, including EGI, that is either a Service Provider and/or a Service Recipient, setting out the final projected CCAM cost allocations for the year and the Services Charge to be paid by each Service Recipient (the "**CCAM Report**").

5.3 Upon request by EGI, the Parties shall work together to prepare and execute a confirmation notice substantially in the form set out in Schedule 3 to evidence their agreement with the projected CCAM cost allocations for any year during the Term.

5.4 For clarity, as described further in the CCAM, EI shall true-up the Service Charges, from time to time, if there is a material difference between the projected CCAM cost allocation set out in the CCAM Report for a Service Recipient and the actual costs incurred by the applicable Service Providers in any year during the Term.

6. Payment Procedures

The Parties agree that all Service Charges shall be documented and paid in accordance with the Accounting for Intercompany Transaction Policy, as may be amended from time to time.

7. Service Agreement Review and Amendment Process

This Agreement may be amended from time to time upon the approval in writing of the Parties. Version control and archival storage of all amendments shall be the responsibility of EGI.

8. Term and Termination

8.1 This Agreement shall be effective January 1, 2019 and, subject to Section 8.4 below, shall remain in effect until December 31, 2020 (the "**Term**"). The Term shall be automatically renewed for successive one (1) year periods unless EI or EGI delivers written notice of its intention to terminate this Agreement to the other Parties no later than six (6) months prior to the expiration of the then applicable Term. Notwithstanding the foregoing, the Term shall not extend beyond December 31, 2023 unless otherwise approved by the OEB.

8.2 Upon the occurrence of any of the following events, a Party may terminate this Agreement by giving notice of such termination to the other Party:

(a) the other Party becomes subject to an Insolvency Event;

(b) the other Party becomes subject to proceedings for the dissolution, liquidation or winding-up of such Party; or

(c) the other Party materially breaches any provision of this Agreement (other than the failure to pay) or any Senior Supervisory Personnel of the other Party engages in fraud or gross negligence in the performance of its obligations pursuant to this Agreement and, within sixty (60) days after the giving of notice by the Party wishing to terminate this Agreement specifying the nature of such event or default, the Party responsible for such event or default fails to cure such event or default if such event or default is reasonably remediable within such cure period, or if such event or default is not reasonably remediable within such cure period, the Party responsible for such event or default fails to commence to take, within the sixty (60) day cure period, steps to remedy such event or default and to thereafter proceed diligently and as expeditiously as reasonably possible to cure or remedy such default;

8.3 Any termination under Section 8.2 shall become effective upon the date specified in the notice first described in Section 8.2, which date shall not be earlier than: (a) in the case of any of the termination events in subsection 8.2(a) or 8.2(b), the date of delivery of such notice; or (b) in the case of the termination event in subsection 8.2(c), six (6) months after the date of delivery of such notice, unless otherwise agreed to by the Parties; provided, however, that in the event a Party in good faith disputes the occurrence of the event giving rise to the termination right hereunder, such termination shall not become effective until such dispute is finally determined in accordance with Article 16.

8.4 EI may terminate this Agreement for convenience upon six (6) months prior written notice. EGI may terminate this Agreement for convenience immediately in the event that it ceases to be a direct or indirect wholly owned subsidiary of EI.

8.5 Upon termination or expiration of this Agreement:

(a) all rights and obligations under this Agreement shall cease except for:

(i) liabilities and obligations that have accrued prior to such termination, including the obligation to pay any amounts that have become due and payable prior to such termination; and

(ii) those rights and obligations described in accordance with Section 17.3; and

(b) upon written request, the Parties shall comply with the obligation to return or destroy Confidential Information and Personal Information in accordance with Section 12.6.

8.6 During the period between delivery of a termination notice and the date of termination, the Service Provider shall use commercially reasonable efforts to effect an orderly and seamless transition of the Services to the Service Recipient or a new service provider selected by the Service Recipient. Such commercially reasonable efforts shall include but not be limited to the Service Provider: (a) transferring of all books, logs, documents, reports, records, manuals, policies, programs, data or other records related to the Services, whether in written or electronic form, that may be reasonably required by the Service Recipient or a new service provider to perform the Services; and (b) attending meetings with the Service Recipient and/or a new service provider regarding the transition of the Services.

9. Representations and Warranties

Each Party represents and warrants, as to itself, to the other Party that:

(a) it is duly incorporated or formed, validly existing and in good standing under the laws of the jurisdiction of its incorporation or formation. It has all requisite power and authority to enter into and perform its obligations under this Agreement and to carry out the transactions contemplated herein. The execution and delivery of this Agreement and the consummation of the transactions contemplated herein and the performance of its obligations hereunder have been duly and validly authorized by all necessary action by such Party, and this Agreement has been duly executed and delivered;

(b) this Agreement constitutes a valid and binding obligation, enforceable against in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium and other similar laws affecting creditor's rights generally and general principles of equity;

(c) the execution, delivery and performance of this Agreement, the consummation of the transactions contemplated hereby, and the compliance with the provisions hereof, will not, with or without the passage of time or the giving of notice or both:

(i) conflict with, constitute a breach, violation or termination of, give rise to any right of termination, cancellation or acceleration of or result in the loss of any right or benefit under, any agreement to which it is a party that would have a material adverse effect on the transactions contemplated hereby or on its ability to perform its material obligations contemplated hereunder;

(ii) conflict with or violate its organizational documents; or

(iii) violate any laws applicable to it or its properties or assets that would have a material adverse effect on the transactions contemplated hereby or on its ability to perform its material obligations contemplated hereunder.

(d) there is no injunction or restraining order, arbitration or claim pending against it which restrains or prohibits the consummation of the transactions and the performance of its obligations contemplated by this Agreement.

10. Limits of Liability

10.1 Liability of the Service Provider

Notwithstanding anything contained in this Agreement, no Service Provider or Service Provider Representative shall, either directly or indirectly, be liable, answerable or accountable to a Service Recipient or Service Recipient Representative to which it provides Services, under this Agreement or otherwise at law or in equity, for:

(a) any loss resulting from, incidental to or relating to a breach by any Service Provider Representative of any of the terms of this Agreement, the performance or non-performance of the Services by any Service Provider Representative (irrespective of whether such Services have been provided before the Effective Date, including any exercise or refusal to exercise a discretion, any mistake or error of judgement or any act or omission believed by the Service Provider Representative to be within the scope of authority conferred thereon by this Agreement, unless the proximate cause of such loss resulted from the fraud or gross negligence of any Senior Supervisory Personnel of the Service Provider Representative, in performing the Services, in which case the benefit of this Section 10.1(a) shall not apply to the Service Provider Representative.

(b) any loss resulting from, incidental to or relating to a breach by any Service Provider Representative of any of the terms of this Agreement, the performance or non-performance of the Services by any Service Provider Representative (irrespective of whether such Services have been provided before the Effective Date), where the proximate cause of such loss is attributable to: (i) a Service Provider Representative acting in accordance with the instructions of the Service Recipient (ii) any action or omission that occurred with the Service Recipient's advance consent; or (iii) if applicable, the Service Recipient's failure to approve an item in any budget that was proposed by the Service Provider where the omission of the Service, activity or operation proposed was the cause of the claim asserted against or loss suffered by the Service Recipient; or

(c) any loss resulting from, incidental to, or relating to any act or omission by any Service Provider Representative (irrespective of whether such act or omission occurred prior to the Effective Date), provided that such act or omission is based upon the Service Provider Representative's reliance on: (i) statements of fact of other persons (excluding any Service

Provider Affiliates) who are considered by the Service Provider to be knowledgeable of such facts; or (ii) the opinion or advice of or information obtained from any expert.

Each Party acknowledges and agrees that the limits of liability provided for in this Section 10.1 shall not only be enforceable by the Service Provider and the Service Provider's Affiliates, but shall also be enforceable directly by each of the Service Provider Representatives.

10.2 No Liability for Certain Losses

Notwithstanding anything to the contrary in this Agreement, in no event shall a Service Provider (or any Service Provider Representatives) or a Service Recipient (or any Service Recipient Representatives) be liable to the other for any exemplary, punitive, remote, speculative, consequential, indirect, special or incidental damages or loss of profits; provided that, if any Service Recipient Representative or Service Provider Representative is subject to a Third Party Claim for any such damages and the Indemnifying Party is obligated to indemnify such Service Recipient Representative or Service Provider Representative, as applicable, for the matter that gave rise to such damages, the Indemnifying Party shall be liable for, and obligated to reimburse such Service Recipient Representative or Service Provider Representative, as applicable, for, such damages.

10.3 Exclusive Remedy

As between any Service Provider Representatives and any Service Recipient Representatives pursuant to this Agreement, the indemnification provisions set forth in Article 11 and the termination provisions set forth in Article 8 will be the sole and exclusive remedies of the Parties. Neither Party nor any of its respective successors or assigns shall have any rights against the other Party or its Affiliates with respect to the subject matter of this Agreement other than as expressly contemplated. The remedies contained in Article 8 and Article 11 are given and accepted in lieu of (a) any express or implied warranties by any Service Provider, including warranties of merchantability, fitness for a particular purpose, or good and workmanlike performance, and (b) any obligation, liability, right, claim or remedy at law or in equity arising out of any defect in the Services whether such claim arises under contract, negligence, intentional misconduct, other tort, breach of warranty, deceptive trade practice, other statutory cause of action, strict liability, product liability, or other theory of liability. Except as expressly set forth herein, no Service Provider makes any representations or warranties (expressed, implied, oral or otherwise) regarding any aspect of its performance of (or failure to perform) the Services including warranties of merchantability, fitness for a particular purpose, or good and workmanlike performance or its other duties and obligations under this Agreement.

11. Indemnification

11.1 Indemnification by a Service Recipient

Subject to Section 10.2, a Service Recipient shall be liable to and, as a separate covenant, shall indemnify, protect, defend, release and hold harmless each Service Provider Representative from and against any claims asserted by or on behalf of any person, and for any losses, incurred by, borne by or asserted against any Service Provider Representative and which in any way arise from or relate in any manner to this Agreement or the performance or non-performance of Services (irrespective of whether such Services have been provided before the Effective Date), except to the extent the proximate cause of such claim or loss resulted from the fraud or gross negligence of any Senior Supervisory Personnel of the Service Provider Representative, in performing the Services.

11.2 Indemnification by a Service Provider

Subject to the limits and restrictions on the liability of a Service Provider set forth in Sections 10.1 and 10.2, a Service Provider shall be liable to and, as a separate covenant, shall indemnify, protect, defend, release and hold harmless each Service Recipient Representative from and against any claims asserted by or on behalf of any person, and for any losses, incurred by, borne by or asserted against any Service Recipient Representative to the extent the proximate cause of such claim or loss resulted from the fraud or gross negligence of any Senior Supervisory Personnel of the Service Provider, in performing the Services.

11.3 Method of Asserting Claims

(a) If a Party entitled to indemnification (the "**Indemnified Party**") intends to seek indemnification under this Article 11 from the other Party (the "**Indemnifying Party**") for any claim by a third party (including a governmental authority) (a "**Third Party Claim**"), the Indemnified Party shall give the Indemnifying Party notice of such Third Party Claim for indemnification promptly following the receipt or determination by the Indemnified Party of actual knowledge or information as to the factual and legal basis of any Third Party Claim which is subject to indemnification and, promptly following receipt of notice of such Third Party Claim. The failure of or delay by an Indemnified Party to so notify the Indemnifying Party (as set forth above) shall not relieve the Indemnifying Party of its indemnification obligations to the Indemnified Party, however the liability which the Indemnifying Party has to the Indemnified Party pursuant to the terms of this Article 11 (and for which the Indemnifying Party will be obligated to indemnify the Indemnified Party in respect of) shall be reduced to the extent that any such delay in or failure to give notice as required in this Agreement prejudices the defence of any such Third Party Claim, or otherwise results in any increase in the liability which the Indemnifying Party has under its indemnity provided for therein.

(b) The Indemnifying Party, at its sole cost and expense, shall have the right to assume the defense of any Third Party Claim brought against the Indemnified Party with counsel designated by the Indemnifying Party and reasonably satisfactory to the Indemnified Party; provided that the Indemnifying Party will not, without the Indemnified Party's prior written consent (such consent not to be unreasonably withheld, conditioned, or delayed), settle, compromise, consent to the entry of any judgement in or otherwise seek to terminate any Third Party Claim in respect of which indemnification may be sought unless such settlement, compromise, consent or termination includes a release of the Indemnified Party from all liabilities arising out of such Third Party Claim. The Indemnified Party will give to the Indemnifying Party and its counsel reasonable access to all business records and other documents relevant to such defence or settlement and shall permit them to consult with the employees and counsel (if any) of the Indemnified Party.

(c) Notwithstanding the foregoing:

(i) If the defendants in any Third Party Claim include both the Indemnified Party and the Indemnifying Party, and the Indemnified Party is advised by counsel that there are legal defences available to the Indemnified Party that are additional to those available to the Indemnifying Party and that in such circumstances representation by the same counsel would be inappropriate; or

(ii) If the Indemnified Party shall have reasonably concluded that the Indemnifying Party is not taking or has not taken, all necessary steps to diligently defend such Third Party Claim, the Indemnified Party has provided written notice of same to the Indemnifying Party, and the Indemnifying Party has not rectified the situation within a reasonable time,

then the Indemnified Party shall have the right to retain separate counsel, the reasonable costs of which shall be at the Indemnifying Party's expense, to represent the Indemnified Party and to otherwise participate in the defense of such claim on behalf of such Indemnified Party. For further certainty, only one legal firm for all indemnified parties may be engaged at the expense of the Indemnifying Party.

(d) Notwithstanding anything contained in this Agreement, an Indemnified Party shall have the right, at its sole cost and expense, to retain counsel to separately represent it in connection with the negotiation, settlement or defence of any Third Party Claim provided, for further certainty, that such counsel shall not, unless agreed by the Indemnifying Party, assume control of the negotiation, settlement or defence on behalf of the Indemnifying Party.

(e) Except to the extent expressly provided in this Agreement, no Indemnified Party shall settle any Third Party Claim with respect to which it has sought or intends to seek indemnification pursuant to this Article 11 without the prior written consent of the Indemnifying Party, which consent shall not be unreasonably withheld, conditioned, or delayed.

(f) If the Indemnifying Party does not assume the defence of any Third Party Claim brought against the Indemnified Party, then the Indemnified Party shall have the right to do so on its own behalf and all such expense in so doing shall be added to the amount of the claim for indemnification by such Indemnified Party as against the Indemnifying Party.

11.4 Net Amount

If an Indemnifying Party is obligated to indemnify and hold any Indemnified Party harmless under this Article 11, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's out-of-pocket losses (whether paid or payable), net of any such out-of-pocket losses recovered by the Indemnified Party from any other person; provided that the foregoing shall not be construed so as to obligate an Indemnified Party to pursue or seek recovery of any of its out-of-pocket losses from any other person whomsoever, including insurers.

11.5 Third Party Beneficiaries

Each Party acknowledges and agrees that the rights of indemnification provided for in this Article 11 shall not only be enforceable by the Parties but shall be enforceable directly by each of the Service Provider Representatives and the Service Recipient Representatives, and in this respect:

(a) the Service Recipient appoints the Service Provider to act as agent and trustee for the Service Provider Representatives as regards the covenants of indemnification by the Service Recipient given in favour of the Service Provider Representatives pursuant to Section 11.1, and the Service Provider accepts such appointment; and

(b) the Service Provider appoints the Service Recipient to act as agent and trustee for the Service Recipient Representatives as regards the covenants of indemnification by the Service Provider given in favour of the Service Recipient Representatives pursuant to Section 11.2, and the Service Recipient accepts such appointment.

11.6 Subrogation Rights

If an Indemnified Party has a right against a person (other than as against the other Party to be indemnified by the Indemnifying Party) with respect to any damages or other amounts paid by the Indemnifying Party, then the Indemnifying Party shall, to the extent of such payment and to the extent permitted by applicable law, be subrogated to the rights of such Indemnified Party as against such person. Notwithstanding the foregoing, no Indemnifying Party shall be subrogated to any insurance rights of any Indemnified Party.

12. Confidential Information and Personal Information

12.1 Each of the Parties hereto agrees to keep all information provided by the other Party (the "**Disclosing Party**") to it (the "**Receiving Party**") that the Disclosing Party designates as confidential or which ought to be considered as confidential from its nature or from the circumstances surrounding its disclosure ("**Confidential Information**") confidential, and a Receiving Party shall not, without the prior consent of an authorized senior officer of the Disclosing Party, disclose any part of such Confidential Information which is not available in the public domain from public or published information or sources except:

(a) to those of its employees who require access to the Confidential Information in connection with performance of Services hereunder;

(b) as in the Receiving Party's judgement may be appropriate to be disclosed in connection with the provision by the Receiving Party of Services hereunder;

(c) as the Receiving Party may be required to disclose in connection with the preparation by the Receiving Party or any of its direct or indirect holding companies, Affiliates or subsidiaries of reporting documents including, but not limited to, annual financial statements, annual reports and any filings or disclosure required by statute, regulation or order of a regulatory authority; and

(d) to such legal and accounting advisors, valuators and other experts as in the Receiving Party's judgement may be appropriate or necessary in order to permit the Receiving Party to rely on the services of such persons in carrying out the Receiving Party's duties under this Agreement.

12.2 The covenants and agreements of the Parties relating to Confidential Information shall not apply to any information:

(a) which is lawfully in the Receiving Party's possession or the possession of its professional advisors or its personnel, as the case may be, at the time of disclosure and which was not acquired directly or indirectly from the Disclosing Party;

(b) which is at the time of disclosure in, or after disclosure falls into, the public domain through no fault of the Receiving Party or its personnel;

(c) which, subsequent to disclosure by the Disclosing Party, is received by the Receiving Party from a third party who, insofar as is known to the Receiving Party, is lawfully in possession of such information and not in breach of any contractual, legal or fiduciary obligation to the Disclosing Party and who has not required the Receiving Party to refrain from disclosing such information to others; or

(d) disclosure of which the Receiving Party reasonably deems necessary to comply with any legal or regulatory obligation which the Receiving Party believes in good faith it has.

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

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

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

(c) implement such policies and procedures thoroughly and effectively.

12.4 EI acknowledges that EGI may not release to EI or its Affiliates, and EI and its Affiliates shall not have access to, any confidential information relating to an EGI consumer, marketer or other service customer ("**Confidential Customer Information**"), unless aggregated such that individual Confidential Customer Information cannot be reasonably identified, without consent in writing from the applicable consumer, marketer or other EGI service customer, except where required for purposes of billing or market operation, law enforcement, complying with legal requirements or processing past due accounts of the consumer that have been passed to a debt collection agency. EI acknowledges and shall ensure that its employees and its Service Provider Representatives and Service Recipient Representatives that are involved in providing or receiving Services will, upon request of EGI, receive Code training and, in the event they inadvertently receive or gain unauthorized access to any Confidential Customer Information, will (a) promptly advise EGI and (b) at EGI's request, immediately destroy all copies of such Confidential Customer Information.

12.5 Each Party shall be entitled to periodically conduct reviews of the procedures implemented by the other Party in relation to the obligations described in this Article 12.

12.6 Upon the termination of this Agreement and written request by a Party, the other Party shall immediately return all Confidential Information and Personal Information provided by such Party, and all copies thereof in its possession or control (other than such Confidential Information or Personal Information which continues to be used or relevant to the provision of the Services), or destroy such information and copies and certify in writing to such Party that such destruction has been carried out; provided that, to the extent Confidential Information is electronically stored, the other Party shall destroy such electronically stored Confidential Information only to the extent that it is reasonably practical to do so and that doing so is consistent with applicable law. The confidentiality of any copies retained by any Party pursuant to this paragraph shall be maintained in accordance with the terms of this agreement and access to any such copies shall be restricted to persons whose primary functions are legal, compliance or information technology services.

13. Audit Rights

13.1 Each Party shall have the right, at its own cost and by notice to the other Party at reasonable hours to, or to direct a third party to, examine and make copies of the books, records and charts of the other Party to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to any of the provisions of this Agreement and to comply with any government filing requirements. Such books, records and charts shall be preserved in accordance with the records retention policies of such Party, provided the books, records or charts related to any matter disputed between the Parties or which is the subject of an outstanding application or proceeding before a governmental authority shall be preserved until such dispute is settled or such application or proceeding has been finally resolved, whichever is later. The Parties' rights under this Article 13 to view books, records and charts to make copies:

(a) for internal purposes, shall subsist for a period of two (2) years from the end of the calendar year to which such books, records and charts relate, during the Term and for a period of two (2) years after expiration or termination of this Agreement, and

(b) for the purposes of complying with the requirements of governmental authorities, including tax authorities, shall subsist for a period of seven (7) years from the end of the calendar year to which such books, records and charts relate, during the Term and for a period of two (2) years after expiration or termination of this Agreement.

13.2 If this Agreement has been terminated or has expired, each Party's obligations to preserve such books, records and charts in accordance with its records retention policy shall continue. A Party may fulfill such obligations by continuing to preserve such books, records, and charts or by delivering them to EGI.

14. Force Majeure

If either Party is rendered unable by force majeure to carry out its obligations under this Agreement, other than a Party's obligation to make payments to the other Party, that Party shall give the other Party prompt written notice of the event giving rise to force majeure with reasonably full particulars concerning it. Thereupon, the obligations of the Party giving the notice, so far as they are affected by the force majeure, shall be suspended during, but no longer than the continuance of, the force majeure. The affected Party shall use all reasonable diligence to remove or remedy the force majeure situation as quickly as practicable.

15. Services

15.1 Each Service Provider shall, and shall cause its Service Provider Representatives to, perform the Services exercising the care, diligence and skill of an experienced and prudent service provider performing similar services in similar circumstances and in accordance with the highest generally accepted industry standards. Each Service Provider shall, and shall cause its Service Provider Representatives to, use commercially reasonable efforts to perform the Services in accordance with any additional instructions received from the Service Recipient; provided, however, that the Service Provider and its Service Provider Representatives shall not be required to incur any additional costs related to such request.

15.2 For clarity, the Parties acknowledge and agree that each Party may, as it deems necessary, use its Affiliates to perform any of the Services.

16. Dispute Resolution Process

16.1 In the event that the applicable managers of the Parties cannot resolve an issue related to the nature or performance of the Services, the amount of the cost allocations, or the interpretation of this Agreement within ten (10) Business Days of the date that written notice of the disputed issue is received by the non-disputing Party from the disputing Party, then either Party may send a written notice of the dispute to the responsible executives to be escalated upward through the respective organizations of the Parties, to Director, Vice-President and/or President, for resolution within twenty-one (21) Business Days after the receipt by the applicable executive of the notice. If required, the President of EGI shall make a final determination which shall be binding on the Parties. The Director of each of the Parties' Accounting Operations groups, or equivalent level of Finance personnel, shall facilitate this dispute resolution process.

16.2 Upon mutual agreement of the Parties, any dispute or issue of interpretation arising hereunder may be jointly referred for non-binding guidance or arbitration to an external facilitator with recognized expertise in the subject matter of the dispute or issue of interpretation.

17. General

17.1 This Agreement is an agreement made under and shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada, without regard to principles of conflicts of laws that, if applied, might require the application of the laws of another jurisdiction. Subject to the terms of this Agreement and of applicable laws, the Parties agree to attorn to the jurisdiction of the Ontario Superior Court for the purpose of resolving any disputes that may arise out of this Agreement that are not to be dealt with in accordance with Article 16.

17.2 Without limiting Section 17.1, each Party hereby waives any and all rights to demand a trial by jury in any legal proceeding arising out of or related to this Agreement.

17.3 The provisions of this Agreement requiring performance or fulfilment after the termination of this Agreement, including Sections 3, 6, 9, 10, 11, 12, 13, 16, 17.1, 17.2, 17.3 and 17.6, and such other provisions as are necessary for the interpretation thereof and any other provisions hereof, the nature and intent of which is to survive termination of this Agreement, will survive the termination of this Agreement.

17.4 Each Party shall, from time to time, and at all times, do such further acts and execute and deliver all such further deeds and documents as shall be reasonably requested by each other Party in order to fully perform and carry out the terms of this Agreement.

17.5 The relationship among the Parties under this Agreement is limited to the purpose herein. Nothing in this Agreement shall be deemed to constitute, create or give effect to or otherwise recognize any partnership, joint venture, or formal business entity among the Parties under this Agreement.

17.6 Any notice, request, demand, direction or other communication required or permitted to be given or made under this Agreement to a Party shall be in writing and may be given by hand delivery to the Party to whom it is addressed or sent by electronic mail to such party at its address noted below or at such other address of which notice may have been given by such Party.

(a) **EI**:

Enbridge Inc.

Address:	Fifth Avenue Place, 200, 425 – 1st Street S.W. Calgary, AB T2P 3L8
Attention:	Vice President, Corporate Law Department
Email:	legalnotices@enbridge.com

(b) **EGI:**

Enbridge Gas Inc.

Address:	500 Consumers Road North York, ON M2J 1P8
Attention:	Law Department
Email:	EGILawContracts@enbridge.com

Any such electronic mail shall be deemed to have been received at the opening of business at the premises of such addressee on the first Business Day following the transmission of such notice.

17.7 This Agreement may be executed in counterparts, no one of which needs to be executed by the Parties. Each counterpart, including an electronic transmission of this Agreement, shall be deemed to be an original and shall have the same force and effect as an original. All counterparts together shall constitute one and the same instrument.

17.8 This Agreement will enure to the benefit of and be binding upon the Parties and their respective successors. This Agreement may not be assigned by either Party without the prior written consent of the other Party.

17.9 The division of this Agreement into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder", and similar expressions refer to this Agreement and not to any particular section or other portion hereof. Unless something in the subject matter or context is inconsistent therewith, references herein to articles and sections are to articles and sections of this Agreement. Words importing the singular number shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neuter genders and vice versa, and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and vice versa.

17.10 In the event that one or more of the provisions contained in this Agreement shall be invalid, illegal or unenforceable in any respect under any applicable law, the validity, legality or enforceability of the remaining provisions hereof shall not be affected or impaired thereby. Each of the provisions of this Agreement is hereby declared to be separate and distinct.

17.11 No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision (whether or not similar) nor shall any waiver constitute a continuing waiver unless otherwise expressed or provided.

17.12 This Agreement constitutes the whole and entire agreement between the Parties respecting the subject matter of the Agreement and supersedes any prior agreement, undertaking, declarations, commitments, representations, verbal or oral, in respect thereof.

Remainder of page intentionally blank.

Dated as of the date first written.

ENBRIDGE INC.

Per: Patrick Murray
Patrick Murray (Sep 28, 2020 11:41 MDT)

Patrick R. Murray

Senior Vice President & Chief Accounting Officer

ENBRIDGE GAS INC.

Per:

Cynthia L. Hansen

President

SCHEDULE 1
SERVICES

Finance	
Purpose	Trusted advisors driving value through disciplined financial management, insightful analysis and rigorous compliance.
Service Description	1. Provide timely and accurate information on actual performance through monthly financial reports and quarterly external reporting. 2. Provide timely and accurate information of future financial performance. 3. Partner in decision making by supporting the development of business unit strategy and deep technical expertise as needed. 4. Reliably manage finance operations executing transactional accounting and execution of effective capital, tax and risk programs, maintaining strong control environment and improving processes and systems. 5. Investor Relations: Communicate corporate financial and operational information publicly.

Technology and Information Systems (TIS)	
Purpose	Drive competitive advantage for the businesses of the Service Provider by optimizing information and technology.
Service Description	1. Core infrastructure and operations: Information Technology (IT) Support services, backup and storage. IT operations and monitoring etc. 2. Enterprise Business Applications: Multiple ERP Platforms and applications for corporate functions. 3. Enterprise Architecture & Data: Advanced Analytics, Data Governance, Enterprise Business Intelligence, IT Architecture. 4. Cyber Security Governance, Risk and Compliance, Security Operations, Network Security and Identity and Access Management. 5. TIS Office of the Chief Information Officer: Enterprise Records Management, Technology Direction and Compliance, Vendor Management, TIS Project Management Office.

Human Resources (HR) & Benefits Pool	
Purpose	Enable Strategy through inspired and capable people.
Service Description	1. Attract and source diverse talent in an inclusive environment. 2. Train and develop our people. 3. Support people & workforce management activities. 4. Effective execution of talent management programs. 5. Effective organizational culture reflective of our values to deliver superior results. 6 HR advice and consultation services.

Real Estate and Workplace Services	
Purpose	Provide a consistent cost-effective workplace that enables the business to achieve its strategic objectives in an efficient and collaborative environment.
Service Description	1. Full life cycle of demand analysis 2 Feasibility 3. Planning 4. Execution 5. Procurement 6. Operations 7. Asset management 8. System assessment 9. Development of enterprise wide policies

Supply Chain Management (SCM)	
Purpose	Create value for the business by optimizing the enterprise spend for the acquisition and logistics of goods and services at competitive costs.
Service Description	1. Business Partners a) Business Unit Facing: Primary point of contact for internal customers with the responsibility to advise customers and SCM on the best ways to translate Business Unit needs into concrete steps that enable our customer's success. b) SCM Facing: Improve supplier delivery and performance, leveraging/driving SCM processes such as Supplier Performance

	Management, Contract Conformance, Suppliers Relationship Management, etc. c) Sourcing: Regional sourcing of services and materials. 2. Supply Chain Service Centre a) Customer Support Centre: Centrally manage inbound purchase requisitions for goods and services across the enterprise. b) Procurement Centre: Centrally manage tactical sourcing, transactional order processing, and logistics transactions activities for good and services across the enterprise. c) Enterprise Procurement Support: Collaborate with SCM Stakeholders, TIS and customers to enable Service Supply Chain infrastructure for efficient and compliant processing (e.g., tools, process improvements, data, etc.).

Legal	
Purpose	To provide comprehensive legal services to support corporate, commercial, litigation, regulatory and other business needs of Service Recipient, working with external counsel as necessary.
Service Description	1. Corporate Law Governance 2. Commercial Support 3. Litigation and Human Resources Support 4. Regulatory Support 5. Ethics & Compliance 6. Legal Services Operations

Corporate Development Office	
Purpose	Develop, refine, communicate and execute Strategic (business) plan.
Service Description	1. Corporate Strategy: Develop and disseminate a strategic plan to position the company for sustainable growth and value creation over the near, medium and long-term. 2. Investment Review: Guide capital allocation (investment) process and decisions.

	3. Assess and create investment opportunities for inorganic growth (outside existing platforms) at the enterprise level. Geographical / community expansion services are not included under this corporate function.

Public Affairs and Communications	
Purpose	Serve Service Recipient as a valued partner, providing differentiated and meaningful stakeholder communication and engagement that manages risks and builds trust and confidence.
Service Description	1. Engagement strategies that support the business objectives including Enterprise Communications, Corporate Social Responsibility, community investment guidance and industry relations. 2. Project and operational advancement including public and agency participation plans, community engagement, indigenous engagement, external affairs, conflict resolution and regional communications. 3. Enabling leadership and advocacy.

Executive	
Purpose and Service Description	1. Chief Executive Officer department provides senior leadership, overall management guidance and advice regarding the financial and operational affairs. 2. Approval and communication of policies and controls (capital spending, operating spending, Authorized Spending Limits Policy, Risk management policies, etc.). 3. Provides ultimate responsibility for all personnel, safety & environmental, and regulatory policy issues. 4. Provides ultimate responsibility for governance of the organization with respect to ensuring the proper procedures, policies, processes, people and culture to be successful.

Safety and Reliability (S&R)	
Purpose	Provide programs and field support to enable Industry Leading performance in Safety, Environmental and Lands & Right of Way (ROW).
Service Description	1. Effective Management System: Structure and processes to reveal and manage operational risk.

	2. Effective safety and reliability performance in the operation and construction of the pipeline system. 3. One Enbridge: Safety Program; Environmental Program; ROW Program. 4. Standardized performance reporting and data systems. 5. Standards and assurance processes to achieve industry leading performance.

Aviation	
Purpose	To provide safe, efficient and convenient air transportation to assist in achieving the mission and goals of the company.
Service Description	1. Safe air service in response to company needs including pipeline patrol operations, monitoring right-of-way for adverse conditions impacting persons, property and environment. 2. Provide surveillance for activities around the pipeline over large, inaccessible areas and satisfy requirement of CSA Z662. 3. 24/7 Emergency Response to any pipeline mishap or emergency.

SCHEDULE 2
CENTRAL SERVICES COST ALLOCATION METHODOLOGY

1. Background

Centralized services groups ("**Central Services**")[1] of Enbridge Inc. ("**Enbridge**") perform various functions for the benefit of Enbridge and many of its subsidiary legal entities (the "**Enterprise**"). Costs of Central Services are recorded in centralized cost pools and charged or allocated to individual entities or lines of business ("**LOBs**") on a reasonable basis, as described below, with the intent to match cost causation as closely as possible. The approach documented herein is meant to bring alignment, simplicity and standardization across the Enterprise in respect of the allocation methods for 2019 onward.

This document describes the allocation methodology used to allocate costs from Central Services to LOBs within the Enterprise that meet certain criteria. Any other cost allocations performed by individual LOBs or Business Units ("**BUs**") are outside the scope of this document.

2. Guiding Principles

In arriving at the allocation methodology discussed in this document, the following guiding principles were considered:

i. Corporate costs will be allocated based on a reasonable estimate of the benefit derived by various operating assets; Certain Corporate Business Development and Special Projects costs will be retained at the Corporate office.

ii. Approach should be supported by Regulatory and Tax Services groups.

iii. Reasonable rules of thumb shall be used in developing basis for allocating costs to ensure allocations are formula driven, consistently applied, materially correct and defensible.

iv. Corporate costs will not be allocated back to Corporate by the operating assets, unless material.

v. Corporate allocations will be excluded for purposes of determination of the financial metric of the BU, as part of incentive compensation calculations.

vi. Allocations shall be trued-up at conclusion of each year, or earlier, if material.

3. Businesses Requiring Allocation of the Central Services Costs

Consistent with Enbridge's past practice, the Central Services costs will be allocated on a normalized basis to individual LOBs. The following criteria are used for identifying a LOB that requires allocation.

---

1 Central Services are: Finance, Technology and Information Systems, Human Resources & Benefits Pool, Real Estate and Workplace Services, Supply Chain Management, Law, Corporate Development Office, Public Affairs and Communications, Executive, Safety & Reliability (S&R) and Aviation.

A LOB is:

- 50% or more owned, directly or indirectly, by Enbridge
- Operated by Enbridge
- In operation or expected to be in operation in the first half of the year to which the allocations apply. For clarity, for 2019 allocations, Enbridge will ignore a LOB which is expected to be in operation in the second half of 2019.
- An asset/entity not meeting the parameters listed above, but which has contractual arrangements for being charged allocations of Central Services costs from Enbridge (e.g. Joint Ventures operated by Enbridge).
- Not an equity investment, financing or holding company within the Enterprise.

For greater certainty, it is intended that Central Services costs will be allocated to individual operating LOBs directly, and that allocations to groups of businesses or employee services companies (as was done by legacy companies prior to the Enbridge-Spectra merger) will be minimized to the extent practicable. The allocation process at employee services companies, for costs other than those which are now related to Central Services, would remain the responsibility of such companies.

Utilizing the above criteria, and in consultation with BUs, a list of LOBs requiring allocations of Central Services Costs is prepared and documented and updated annually or as required.

4. Central Services Cost Pool

A Central Services "Cost Pool", comprising the costs of all Central Services, has been determined utilizing the cost centre ("**CC**") mappings under the Central Services cost allocation methodology. Each CC is ultimately assigned to a VP in charge of that area. Generally, all CCs linked to VPs who are part of one of the Central Services will be included in the Central Services Cost Pool. CCs in the Central Services Cost Pool are divided into two buckets: (1) **Allocable Costs**, which are allocated to individual operating entities using the methodology prescribed by this document; and (2) **Direct Charged Costs**, which represent costs that are booked directly in LOBs where they belong and hence excluded from the allocations process.

A. Direct Charged Costs

- All costs residing in the "Direct Charged" category of CCs under Law, Finance and S&R are excluded from the cost allocation pool and directly charged to the LOB they roll up to. Following are examples of Direct Charged Costs:
  - S&R – Some of the CCs belonging to S&R have costs belonging to specific LOBs. These costs are recorded as Direct Charged Costs in CCs which are dedicated for specific LOBs. This allows for the tracking of such costs by LOBs and facilitates the recovery of these costs from insurance providers and/or shippers.
  - External Legal Fees – From 2019 onward, external legal fees are centralized. Law is responsible for budgeting Enterprise external legal fees, maintaining all such

relationships with external counsels and approving all invoices. As a result, specific Direct Charged CCs have been created where Law has budgeted such costs under specific LOBs.

- External Audit Fees – To the extent audit fees are billed directly to individual operating entities, such fees are budgeted to the appropriate LOBs as Direct Charges and excluded from the pool of allocable costs.

5. Allocable Costs - Directly Attributable (including those attributable to Capital Projects)

BUs/Departments will be asked to provide input as to whether a portion of a CC is directly attributable to Capital Projects, or to other LOBs. For a majority of cases, it is expected that the direct attribution will be based on time estimates. Any amount remaining after the direct attribution will form part of the Central Services Cost Pool for allocation and thereby be an "Allocable Cost". BUs/Departments are contacted in or around the second week of July to seek their input.

6. Allocation Method

To the extent a cost is directly attributable to a LOB (see section 5 above); such component of the cost will be assigned directly to that LOB (Directly Attributable Costs), with any residual balance being included in the Central Services Cost Pool for allocation.

Costs in the general cost pool will be allocated using an allocation formula. In a majority of cases, it is expected that the extent of utilization of a shared service is driven by the size of and contribution by an operating LOB. Therefore, a Modified 3-Factor Formula ("**3FF**") is utilized to allocate such costs to LOBs.

The three factors used in the Modified 3FF are: Revenues; Gross Book Value of Property, Plant and Equipment ("**PP&E**"); and Payroll. These terms are explained further as follows:

i. The term "revenues" means gross revenues for each LOB, with the exception of Energy Marketing businesses (Tidal US and Tidal Canada), Gas Distribution businesses and Gas Pipelines and Processing businesses for which net revenues (gross revenues minus commodity cost or gas distribution cost) will be used. Energy Marketing businesses operate on a margin bases, but recognize revenues on a gross basis; therefore, net revenue is recognized as a more reasonable basis of allocation. Likewise, for Gas Distribution businesses, gas distribution cost is a flow-through cost; therefore, net revenue is considered to be a more reasonable basis. Revenues from Gas Pipelines and Processing ("**GPP**") businesses also inflate due to commodity prices; therefore, net revenue will also be a reasonable basis for GPP. In cases where unrealized derivative gains or losses on non-qualifying economic hedges are recorded within revenues, such gains or losses will also be excluded for the purpose of the Modified 3FF.

ii. The term "payroll" comprises base pay and overtime for both permanent and contract employees.

iii. Any material impairments are excluded from PP&E gross amounts used for this calculation.

The term "Modified" is used for the 3FF to distinguish it from the Massachusetts 3-Factor Formula, which requires the use of "gross revenues". The 3-Factor Formula apportions a centralized cost to LOBs based on a LOB's "revenues", "assets" and "payroll" in relation to the "revenues", "assets" and "payroll" of all LOBs requiring allocation. Following is a simple example of the application of the Modified 3FF:

Assumptions:

The Company has 3 LOBs that require allocation of a corporate cost of $100,000. Revenues, assets and payroll of these LOBs are provided below, along with the allocation calculation.

	Input Amounts			Stand Alone Percentage			Weighted Percentage				
	Revenues	NBV PP&E	Payroll	Revenues	NBV PP&E	Payroll	Revenues	NBV PP&E	Payroll	Total Weight	Cost Allocation
				(a)	(b)	(c)	(A)=(a)x0.33	(B)=(b)x0.34	(C)=(c)x0.33	(A)+(B)+(C)	
LOB 1	100	800	80	16.67%	16.00%	22.86%	5.50%	5.44%	7.54%	18.48%	18,480
LOB 2	200	1300	100	33.33%	26.00%	28.57%	11.00%	8.84%	9.43%	29.27%	29,270
LOB 3	300	2900	170	50.00%	58.00%	48.57%	16.50%	19.72%	16.03%	52.25%	52,250
Total	600	5000	350	100.00%	100.00%	100.00%	33.00%	34.00%	33.00%	100.00%	100,000

7. Recoveries for Cost Centres in LOBs outside of Corporate

A number of CCs relating to Central Services groups still reside in LOBs outside of the Corporate legal entity. As a result, from the perspective of individual LOBs, such CCs, if unadjusted, will impact the LOB's bottom line. Where a CC is added to the centralized cost pool and gets allocated to businesses other than its parent LOB, the parent LOB will receive a credit from Corporate for such allocations.

As an example, if a CC in EPI contains costs of an IT team that is serving various other LOBs, then the cost in that CC will first be brought into the Central Services Cost Pool by way of providing a credit to EPI, and then such costs will be allocated out to those receiving services from the IT team. The Corporate Finance team has developed and implemented a mechanism to track and adjust such credits.

8. Documentation

A Central Services manager is responsible to:

i. Provide a service description that outlines the services provided and the basis of allocation of any directly attributable service to specific LOBs receiving the Central Services and cost allocation;

ii. Complete the Central Services budget (and subsequent forecasts) and provide any changes in the previously provided direct cost allocation input;

iii. Ensure all cost allocations are reflective of the economic benefit received by the LOBs;

iv. Provide communication and support during any resolution process in the case of allocations being questioned by the receiving LOB;

v. Keep documentation of the foundation for the budget including time estimates used for any direct charge to capital projects or to specific LOBs;

vi. Review monthly actual costs versus budget to ensure their costs and recoveries are tracking to expected levels, explain any material variances and work with the Corporate Finance team to ensure any true-up of cost allocations are appropriate and reasonable;

9. Contacts

Inquiries relating to allocation of Central Services costs can be sent to Corporate.Allocations@enbridge.com.

AMENDING AGREEMENT

THIS AMENDING AGREEMENT is made as of the 1st day of January, 2021

B E T W E E N:

ENBRIDGE INC.

("EI")

\- **and –**

ENBRIDGE GAS INC.

("EGI")

WHEREAS:

A. The parties entered into an Intercorporate Services Agreement dated as of January 1, 2019 (the "Agreement").
B. The parties now wish to amend the Schedules of the Agreement as set out in this Amending Agreement.

NOW THEREFORE, in consideration of the premises, the mutual covenants contained in this Amending Agreement and other consideration (the receipt and sufficiency of which are acknowledged), the parties agree as follows:

1. Schedule 1 of the Agreement is hereby superceded and replaced with the attached Schedule 1.

2. Schedule 2 of the Agreement is hereby superceded and replaced with the attached Schedule 2.

3. This Amending Agreement shall enure to the benefit of and be binding upon the parties hereto, their respective successors and permitted assigns.

4. The parties agree that each of them shall, upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Amending Agreement.

Remainder of page intentionally blank.

5. Except as provided in this Amending Agreement, all provisions of the Agreement remain in full force and effect, unamended.

TO WITNESS THEIR AGREEMENT, the parties have duly executed this Amending Agreement as of the date first above written.

ENBRIDGE INC.	**ENBRIDGE GAS INC.**
By: Patrick Murray Patrick Murray (Oct 18, 2022 15:43 MDT)	By: Michele Harradence Michele Harradence (Oct 18, 2022 18:04 EDT)
Patrick R. Murray	Michele E. Harradence
Senior Vice President & Chief Accounting Officer	President

SCHEDULE 1
SERVICES

Finance	
Purpose	Trusted advisors driving value through disciplined financial management, insightful analysis and rigorous compliance.
Service Description	1. Provide timely and accurate information on actual performance through monthly financial reports and quarterly external reporting. 2. Provide timely and accurate information of future financial performance. 3. Partner in decision making by supporting the development of business unit strategy and deep technical expertise as needed. 4. Reliably manage finance operations executing transactional accounting and execution of effective capital, tax and risk programs, maintaining strong control environment and improving processes and systems.

Technology and Information Systems (TIS)	
Purpose	Drive competitive advantage for the businesses of the Service Provider by optimizing information and technology.
Service Description	1. Core infrastructure and operations: Information Technology (IT) Support services, backup and storage. IT operations and monitoring etc. 2. Enterprise Business Applications: Multiple ERP Platforms and applications for corporate functions. 3. Enterprise Architecture & Data: Advanced Analytics, Data Governance, Enterprise Business Intelligence, IT Architecture. 4. Cyber Security Governance, Risk and Compliance, Security Operations, Network Security and Identity and Access Management. 5. TIS Office of the Chief Information Officer: Enterprise Records Management, Technology Direction and Compliance, Vendor Management, TIS Project Management Office.

Human Resources (HR) & Benefits Pool	
Purpose	Enable Strategy through inspired and capable people.
Service Description	1. Attract and source diverse talent in an inclusive environment. 2. Train and develop our people. 3. Support people & workforce management activities. 4. Effective execution of talent management programs. 5. Effective organizational culture reflective of our values to deliver superior results. 6. HR advice and consultation services.

Real Estate and Workplace Services (REWS)	
Purpose	Provide a consistent cost-effective workplace that enables the business to achieve its strategic objectives in an efficient and collaborative environment.
Service Description	1. Full life cycle of demand analysis 2. Feasibility 3. Planning 4. Execution 5. Procurement 6. Operations 7. Asset management 8. System assessment 9. Development of enterprise wide policies

Supply Chain Management (SCM)	
Purpose	Create value for the business by optimizing the enterprise spend for the acquisition and logistics of goods and services at competitive costs.
Service Description	1) Business Partners a) Business Unit Facing: Primary point of contact for internal customers with the responsibility to advise customers and SCM on the best ways to translate Business Unit needs into concrete steps that enable our customer's success. b) SCM Facing: Improve supplier delivery and performance, leveraging/driving SCM processes such as Supplier Performance Management, Contract Conformance, Supplier Relationship Management, etc. c) Sourcing: Regional sourcing of services and materials. 2) Supply Chain Service Centre a) Customer Support Centre: Centrally manage inbound purchase requisitions for goods and services across the enterprise. b) Procurement Centre: Centrally manage tactical sourcing, transactional order processing, and logistics transactions activities for goods and services across the enterprise. c) Enterprise Procurement Support: Collaborate with SCM Stakeholders, TIS and customers to enable Service Supply Chain infrastructure for efficient and compliant processing (e.g., tools, process improvements, data, etc.).

Legal	
Purpose	To provide comprehensive legal services to support corporate, commercial, litigation, regulatory and other business needs of Service Recipient, working with external counsel as necessary.
Service Description	1. Corporate Law Governance 2. Commercial Support 3. Litigation and Human Resources Support 4. Regulatory Support 5. Ethics & Compliance 6. Legal Services Operations

Corporate Development Office (CDO)	
Purpose	Develop, refine, communicate and executive Strategic (business) plan.
Service Description	1. Corporate Strategy: Develop and disseminate a strategic plan to position the company for sustainable growth and value creation over the near, medium and long-term. 2. Investment Review: Guide capital allocation (investment) process and decisions. 3. Assess and create investment opportunities for inorganic growth (Outside existing platforms) at the enterprise level. Geographical / community expansion services are not included under this corporate function. 4. Investor Relations: Communicate corporate financial and operational information publicly.

Public Affairs and Communications (PAC)	
Purpose	Serve Service Recipient as a valued partner, providing differentiated and meaningful stakeholder communication and engagement that manages risks and builds trust and confidence.
Service Description	1. Engagement strategies that support the business objectives including Enterprise Communications, Corporate Social Responsibility, community investment guidance and industry relations. 2. Project and operational advancement including public and agency participation plans, community engagement, indigenous engagement, external affairs, conflict resolution and regional communications. 3. Enabling leadership and advocacy.

Executive	
Purpose and Service Description	1. Chief Executive Officer department provides senior leadership, overall management guidance and advice regarding the financial and operational affairs. 2. Approval and communication of policies and controls (capital spending, operating spending, Authorized Spending Limits Policy, Risk management policies, etc.). 3. Proves ultimate responsibility for all personnel, safety & environmental, and regulatory policy issues. 4. Provides ultimate responsibility for governance of the organization with respect to ensuring the proper procedures, policies, processes, people and culture to be successful.

Safety and Reliability (S&R)	
Purpose	Provide programs and field support to enable Industry Leading performance in Safety, Environmental and Lands & Right of Way (ROW).
Service Description	1. Effective Management System: Structure and processes to reveal and manage operational risk. 2. Effective safety and reliability performance in the operation and construction of the pipeline system. 3. One Enbridge: Safety Program; Environmental Program; ROW Program. 4. Standardized performance reporting and data systems. 5. Standards and assurance processes to achieve industry leading performance.

Enterprise Asset and Work Management (EAWM)	
Purpose and Service Description	1. Manage the lifecycle of physical assets and equipment in order to maximize its lifetime, reduce costs, improve quality and efficiency, health of assets and environmental safety. 2. Develop and implement advanced work management capabilities to deliver work in a more effective and efficient manner.

Aviation	
Purpose	To provide safe, efficient, and convenient air transportation to assist in achieving the mission and goals of the company.
Service Description	1. Safe air service in response to company needs including pipeline patrol operations, monitoring right-of-way for adverse conditions impacting persons, property and environment. 2. Provide surveillance for activities around the pipeline over large, inaccessible areas and satisfy requirement of CSA Z662. 3. 24/7 Emergency Response to any pipeline mishap or emergency.

SCHEDULE 2
CENTRAL SERVICES COST ALLOCATION METHODOLOGY

1. Background

Centralized services groups ("**Central Services**", "**Central Functions**" or "**CFs**")[1] of Enbridge Inc. (**Enbridge**) perform various services and functions for the benefit of Enbridge and many of its subsidiary legal entities (**Enterprise**). Costs of these Central Services are recorded in centralized cost pools and charged or allocated to individual entities or lines of business (**LOBs**) on a reasonable basis, as described below, with the intent to match cost causation as closely as possible. The approach documented herein is meant to improve alignment, simplicity, and standardization across the Enterprise in respect of the allocation methods for 2021 onward.

This document describes the allocation methodology used to allocate costs from Central Services to LOBs within the Enterprise that meet certain criteria (described below) ("**CCAM**")[2]. Any other cost allocations performed by individual LOBs or Business Units (**BUs**) are outside the scope of this document.

2. Guiding Principles

In arriving at the methodology discussed in this document, the following guiding principles were considered:

i. Consistent in employing a standardized methodology across all BUs.

ii. Costs will be allocated based on a reasonable estimate of the benefit derived by various operating entities.

iii. Complies with regulatory requirements and joint venture agreements.

iv. Meets taxation authority requirements.

v. Simple to understand and administer.

vi. Transparent in conveying the source of allocated costs, and the basis for allocating such costs.

vii. Reasonable to business partners and affiliates receiving allocations.

viii. Adaptable to changes in business while leveraging automation to limit manual intervention.

ix. Meets the requirements for cost recovery and compliance.

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1 Central Services, also called Central Functions, are: Finance, Technology Information Systems (TIS), Human Resources (HR), Real Estate and Workplace Services (REWS), Supply Chain Management (SCM), Legal, Corporate Development Office (CDO), Public Affairs and Communications (PAC), Executive, Safety & Reliability (S&R), Enterprise Asset and Work Management (EAWM) and Aviation. Also includes costs managed by Central Services including Insurance, Depreciation and Benefits.

2 Synonymous with Central Functions Cost Allocation Methodology ("CFCAM").

3. Businesses Requiring Allocation of the Central Services Costs

Consistent with Enbridge's past practice, the Central Services costs will be allocated on a normalized basis to individual LOBs. The following criteria are used for identifying a LOB that requires allocation.

A LOB is:

- 50% or more owned, directly or indirectly, by Enbridge
- Operated by Enbridge
- In operation or expected to be in operation in the first half of the year to which the allocations apply. For clarity, for 2021 allocations, Enbridge will ignore a LOB which is expected to be in operation in the second half of 2021.
- An asset/entity not meeting the parameters listed above, but which has contractual arrangements for being charged allocations of Central Services from Enbridge (e.g. Joint Ventures operated by Enbridge).
- Not an equity investment, financing or holding company within the Enterprise.

For greater certainty, it is intended that Central Services costs will be allocated to individual LOBs directly, and that allocations to groups of businesses or employee services companies (as was done by legacy companies prior to the Enbridge-Spectra merger) will be minimized to the extent practicable. The allocation process at employee services companies, for costs other than those which are now related to Central Services, would remain the responsibility of such companies.

Utilizing the above criteria, and in consultation with BUs, a list of LOBs requiring allocations of Central Services costs is prepared and documented and updated annually or as required.

4. CFs Cost Pool

The cost pool comprises costs incurred by all CFs. Costs in each CF are divided into service categories and cost centres (**CCs**). A CC is a department or unit to which costs are charged for accounting purposes. Within a CF, CCs that provide "like" services are grouped to form a service category. Cost allocation occurs at the service category level by applying a cost driver to the costs in each service category. A cost driver represents the level of services received by individual LOBs. A list of service categories and cost drivers is prepared and documented and updated as required.

Costs in the CFs cost pool are charged to individual LOBs as i) direct charged costs or ii) allocable costs as described below. Direct charged costs are booked directly in the LOBs where they belong and hence excluded from the allocations process. For example, an invoice for the audit of an operating LOB will be expensed directly in that LOB. Hence, such costs will be excluded from the cost pool. External legal fees, audit fees, S&R and PAC are some areas where CFs incur costs that are directly charged to specific LOBs.

5. Allocable Costs

Costs in the allocable cost pool are allocated utilizing one of the following methods:

i. Directly attributable costs 100% directed to a segment[3]: Costs captured in CCs which are specifically attributable to a segment or a sub-segment[4]. Such costs are allocated to the segment or sub-segment to which they are specifically attributable and subsequently allocated to individual LOBs within that segment or sub-segment, using a prescribed cost driver.

ii. Directly attributable costs directed to multiple segments: Costs that are directly attributable to multiple segments. Such costs are first assigned to individual segments based on a prescribed driver, such as a time estimate and subsequently allocated to individual LOBs within such segments using another prescribed cost driver.

iii. Indirect cost allocation: Costs that are not covered under any of the categories above. These costs are for services that benefit the Enterprise, and not solely a LOB or a Segment. Hence, these costs are allocated to all operating LOBs utilizing a prescribed cost driver, such as the Modified 3-Factor Formula (3FF).

6. Cost Drivers

Definitions for the cost drivers are set out below:

Cost Driver	Definition
3FF	The three factors of LOB Revenue, Gross Book Value of PP&E, and payroll are used to calculate allocations. The term "payroll" comprises base pay and overtime for both permanent and contract employees. See definitions for Revenue and Gross Book Value of PP&E below.
Balance Sheet Debt	The size of a Segment's debt compared to Enterprise debt.
Capacity Utilization	For each major Enbridge geographic region, apportion costs based on the Segment's number of employees physically located in a region in comparison with total employees from all Segments physically located in that region. The term "employees" consists of permanent and contract employees and excludes Corporate employees.
Directly Attributable	Refers to costs that are specifically attributable to a Segment or Sub-segment.
Donations Value	The factor of the cost of donations incurred by a Segment compared to the total cost of donations incurred across the Enterprise.
Estimated Salary by LOB	Total estimated base pay and overtime pay for both permanent and contract employees for a LOB compared to Enterprise-wide.

3 Enbridge's core businesses, comprised of: Liquids Pipelines, Gas Transmission & Midstream, Gas Distribution & Storage, Renewable Power Generation, Energy Services and Eliminations & Other. EGI belongs to the Gas Distribution & Storage Segment. Synonymous with Business Unit.

4 Further sub-division of a Segment.

Cost Driver	Definition
Flying Hours	The number of flying hours dedicated to each LOB compared to total Enterprise flying hours.
Gross Book Value of PP&E	The factor of gross property, plant & equipment (PP&E) for a LOB compared to gross PP&E of the Enterprise.
High-Level Time Forecasting	The proportion of the total time spent by a service category in servicing a specific Segment or Sub-segment.
HR Business Partners Headcount	The number of HR Business Partners assigned to a Segment compared with the total number of HR Business Partners in the HR CF.
HR Case Volume	The factor of the number of cases completed for a Segment compared to Enterprise-wide cases. In addition, salary by LOB is used as a second step cost driver.
Network Circuit Usage	The amount of network consumption for a Segment compared to the total network consumption across the Enterprise. Consumption refers to the percentage of usage of service.
Number of Invoices	Number of invoices processed by Accounts Payable for a LOB compared to total number of invoices processed by Accounts Payable across the Enterprise.
Revenue	Represents net revenue compared to total revenue across the Enterprise. The term "revenue" refers to gross revenue for each LOB, with the exception of Energy Marketing businesses, Gas Distribution businesses (including EGI), and Gas Pipelines and Processing businesses for which net revenue (gross revenue minus commodity cost or gas distribution cost) is used.
Spend	Total Capital and Operating & Administrative sourceable purchases for a Segment compared to Enterprise-wide.

Modified 3FF

Where a cost is not directly attributable to individual LOBs and there is no other driver that better reflects the consumption of a service, it is generally expected that the extent of utilization of a CF is driven by the size of and contribution by an operating LOB. The Modified 3FF is utilized to allocate such costs to LOBs.

The term "Modified" is used for the 3FF to distinguish it from the Massachusetts 3-Factor Formula, which requires the use of "gross revenues". The 3FF apportions CFs costs to LOBs based on a LOB's "revenues", "assets" and "payroll" in relation to the "revenues", "assets" and "payroll" of all LOBs requiring allocation. The following is a simple example of the application of the Modified 3FF:

Assumptions:

The Company has 3 LOBs that require allocation of a corporate cost of $100,000. Revenues, assets, and payroll of these LOBs are provided below, along with the allocation calculation.

	Input Amounts			Stand Alone Percentage			Weighted Percentage				
	Revenues	NBV PP&E	Payroll	Revenues	NBV PP&E	Payroll	Revenues	NBV PP&E	Payroll	Total Weight	Cost Allocation
				(a)	(b)	(c)	(A)=(a)x0.33	(B)=(b)x0.34	(C)=(c)x0.33	(A)+(B)+(C)	
LOB 1	100	800	80	16.67%	16.00%	22.86%	5.50%	5.44%	7.54%	18.48%	18,480
LOB 2	200	1300	100	33.33%	26.00%	28.57%	11.00%	8.84%	9.43%	29.27%	29,270
LOB 3	300	2900	170	50.00%	58.00%	48.57%	16.50%	19.72%	16.03%	52.25%	52,250
Total	600	5000	350	100.00%	100.00%	100.00%	33.00%	34.00%	33.00%	100.00%	100,000

7. Recoveries for CCs in LOBs outside of Corporate

A number of CCs relating to CFs still reside in LOBs outside of the Corporate LOB. As a result, from the perspective of individual LOBs, such CCs, if unadjusted, will impact the LOB's bottom line. Where a CC relating to such a LOB is added to the centralized cost pool and gets allocated to other LOBs, the originating LOB will receive a credit from Corporate for such allocations.

As an example, if a CC in EGI contains costs of a TIS team that is serving various other LOBs, then the costs in that CC will first be brought into the allocable cost pool, by way of providing a credit to EGI, and then such costs will be allocated out to those entities receiving services from the TIS team.

8. Documentation

A CF's manager is responsible to:

i. Provide a service description that outlines the services provided and the basis of allocation of any directly attributable service to specific LOBs or segments receiving the CFs and cost allocation;

ii. Approve the CF budget (and subsequent forecasts) and provide any changes to the service categories and cost drivers to the affected LOBs;

iii. Ensure all cost allocations are reflective of the economic benefit received by the LOBs;

iv. Provide communication and support during any resolution process in the case the allocations are being questioned by a receiving LOB, or in connection with any audits;

v. Retain documentation of the foundation for the budget and cost drivers.

vi. Review monthly actual costs versus budget to ensure costs are tracking to expected levels; explain any material variances and work with the Corporate Finance team to ensure the cost allocations are appropriate and reasonable.

9. Contacts

Inquiries relating to allocation of CFs costs can be sent to Corporate.Allocations@enbridge.com.

SCHEDULE 3
CENTRAL SERVICES COST ALLOCATION METHODOLOGY
CONFIRMATION NOTICE

SERVICES TO BE PROVIDED DURING THE 2019 YEAR AND ASSOCIATED COSTS

We have discussed the nature and level of the services to be provided by Enbridge Inc. and its Affiliates to Enbridge Gas Inc. and the services to be provided by Enbridge Gas Inc. to Enbridge Inc. and its Affiliates during 2019 pursuant to the Intercorporate Services Agreement effective January 1, 2019 (the "Agreement"), and agree that: (a) the services provided, as described in Schedule 1 to the Agreement; and (b) the cost allocations set out below and detailed in Appendix I hereto, as determined in accordance with the corporate cost allocation methodology attached as Schedule 2 to the Agreement, are acceptable.

TOTAL ALLOCABLE COSTS (rounded to the nearest $100,000): $336.2 M

ENBRIDGE INC.

Patrick Murray
Patrick Murray (Sep 28, 2020 11:41 MDT)

Name: Patrick R. Murray
Senior Vice President &
Chief Accounting Officer

Date: Sep 28, 2020

ENBRIDGE GAS INC.

Name: Cynthia L. Hansen
President

Date: Sep 28, 2020

APPENDIX I[1]

Central Service Allocations		359.6
Other		(36.1)
Total Central Service Allocations		**323.5**
Direct Charged Costs		2.9
Insurance Allocation		9.8
Total Allocations	**$**	**336.2 M**

Central Service	**EGI Total**
Aviation	2.3
Chief Development Office	2.2
Depreciation	23.0
Enterprise Safety and Operational Reliability	3.4
Executive	1.4
Finance	32.1
Human Resources, Benefits & Real Estate & Workplace Services	199.4
Information Technology	70.1
Legal	14.8
Public Affairs and Communication	7.1
Supply Chain Management	3.8
Allocations before corporate adjustment*	359.6
Corporate adjustment & other	(36.1)
Allocations after corporate adjustment	**$ 323.5 M**

*Includes allocations for unregulated operations

[1] Allocation amounts in this Appendix are rounded to the nearest $100,000.

SCHEDULE 3
CENTRAL SERVICES COST ALLOCATION METHODOLOGY
CONFIRMATION NOTICE

SERVICES TO BE PROVIDED DURING THE 2020 YEAR AND ASSOCIATED COSTS

We have discussed the nature and level of the services to be provided by Enbridge Inc. and its Affiliates to Enbridge Gas Inc. and the services to be provided by Enbridge Gas Inc. to Enbridge Inc. and its Affiliates during 2020 pursuant to the Intercorporate Services Agreement effective January 1, 2019 (the "Agreement"), and agree that: (a) the services provided, as described in Schedule 1 to the Agreement; and (b) the cost allocations set out below and detailed in Appendix I hereto, as determined in accordance with the corporate cost allocation methodology attached as Schedule 2 to the Agreement, are acceptable.

TOTAL ALLOCABLE COSTS (rounded to the nearest $100,000): $204.9 M

ENBRIDGE INC.

Patrick Murray
Patrick Murray (Jul 19, 2021 10:28 MDT)

Name: Patrick R. Murray
Senior Vice President &
Chief Accounting Officer

Date: July 19, 2021

ENBRIDGE GAS INC.

Name: Cynthia L. Hansen
President

Date: July 19, 2021

APPENDIX I[1]

Central Service Allocations		212.2
Other		(21.9)
Total Central Service Allocations		**190.3**
Direct Charged Costs		3.0
Insurance Allocation		11.6
Total Allocations	**$**	**204.9 M**

Central Service	**EGI Total**
Aviation	2.2
Chief Development Office	1.6
Depreciation	23.5
Enterprise Safety and Operational Reliability	5.8
Executive	1.1
Finance	27.1
Human Resources, Benefits & Real Estate & Workplace Services	66.8
Information Technology	65.3
Legal	9.2
Public Affairs and Communication	7.6
Supply Chain Management	2.0
Allocations before corporate adjustment*	212.2
Corporate adjustment & other	(21.9)
Allocations after corporate adjustment	**$ 190.3 M**

*Includes allocations for unregulated operations

[1] Allocation amounts in this Appendix are rounded to the nearest $100,000.

SCHEDULE 3
CENTRAL SERVICES COST ALLOCATION METHODOLOGY
CONFIRMATION NOTICE

SERVICES TO BE PROVIDED DURING THE 2021 YEAR AND ASSOCIATED COSTS

We have discussed the nature and level of the services to be provided by Enbridge Inc. and its Affiliates to Enbridge Gas Inc. and the services to be provided by Enbridge Gas Inc. to Enbridge Inc. and its Affiliates during 2021 pursuant to the Intercorporate Services Agreement effective January 1, 2019 (the "Agreement"), and agree that: (a) the services provided, as described in Schedule 1 to the Agreement; and (b) the cost allocations set out below and detailed in Appendix I hereto, as determined in accordance with the corporate cost allocation methodology attached as Schedule 2 to the Agreement, are acceptable.

TOTAL ALLOCABLE COSTS (rounded to the nearest $100,000): $280.3 M

ENBRIDGE INC.

Patrick Murray
Patrick Murray (Oct 18, 2022 15:43 MDT)

Name: Patrick R. Murray
Senior Vice President &
Chief Accounting Officer

Oct 18, 2022
Date:

ENBRIDGE GAS INC.

Michele Harradence
Michele Harradence (Oct 18, 2022 18:04 EDT)

Name: Michele Harradence
President

Oct 18, 2022
Date:

APPENDIX I[1]

Central Service Allocations		271.0
Other		(10.9)
Total Central Service Allocations		**260.1**
Direct Charged Costs		4.8
Insurance Allocation		15.4
Total Allocations	**$**	**280.3 M**

Central Service	**EGI Total**
Aviation	1.6
Chief Development Office	2.4
Depreciation	26.4
Enterprise Asset and Work Management	0.6
Executive	0.6
Finance	28.1
Human Resources, Benefits & Real Estate & Workplace Services	108.2
Legal	8.0
Public Affairs and Communications	4.1
Safety and Reliability	6.8
Supply Chain Management	8.3
Technology Information Systems	75.9
Allocations before corporate adjustment*	271.0
Corporate adjustment & other	(10.9)
Allocations after corporate adjustment	**$ 260.1 M**

*Includes allocations for unregulated operations

[1] Allocation amounts in this Appendix are rounded to the nearest $100,000.

SCHEDULE 3
CENTRAL SERVICES COST ALLOCATION METHODOLOGY
CONFIRMATION NOTICE

SERVICES TO BE PROVIDED DURING THE 2022 YEAR AND ASSOCIATED COSTS

We have discussed the nature and level of the services to be provided by Enbridge Inc. and its Affiliates to Enbridge Gas Inc. and the services to be provided by Enbridge Gas Inc. to Enbridge Inc. and its Affiliates during 2022 pursuant to the Intercorporate Services Agreement effective January 1, 2019 (the "Agreement"), and agree that: (a) the services provided, as described in Schedule 1 to the Agreement; and (b) the cost allocations set out below and detailed in Appendix I hereto, as determined in accordance with the corporate cost allocation methodology attached as Schedule 2 to the Agreement, are acceptable.

TOTAL ALLOCABLE COSTS (rounded to the nearest $100,000): $346.0 M

ENBRIDGE INC.

Patrick Murray
Patrick Murray (Oct 18, 2022 15:43 MDT)

Name: Patrick R. Murray
Senior Vice President &
Chief Accounting Officer

Oct 18, 2022
Date:

ENBRIDGE GAS INC.

Michele Harradence
Michele Harradence (Oct 18, 2022 18:04 EDT)

Name: Michele Harradence
President

Oct 18, 2022
Date:

APPENDIX I[1]

Central Service Allocations		327.6
Other		(2.1)
Total Central Service Allocations		**325.5**
Direct Charged Costs		4.8
Insurance Allocation		15.7
Total Allocations	**$**	**346.0 M**

Central Service	EGI Total
Aviation	2.4
Chief Development Office	3.4
Depreciation	27.6
Enterprise Asset and Work Management	1.8
Executive	1.1
Finance	34.0
Human Resources, Benefits & Real Estate & Workplace Services	112.6
Legal	11.7
Public Affairs and Communications	5.6
Safety and Reliability	7.2
Supply Chain Management	11.7
Technology Information Systems	108.5
Allocations before other*	327.6
Other	(2.1)
Central Service Allocations	**$ 325.5 M**

*Includes allocations for unregulated operations

[1] Allocation amounts in this Appendix are rounded to the nearest $100,000.

Central Functions Costs and Cost Drivers

Line No.	Central Function ($ millions)	2022 Estimate	2024 Test Year	Cost Drivers	
		(a)	(b)	(c)	
1	Aviation	-	-	Flying hours.	
2	CDO	2.4	2.5	High-level time forecasting, 3FF.	
3	EAWM	1.8	1.9	3FF.	
4	Executive	1.1	1.1	3FF.	
5	Finance	35.1	36.7	Directly attributable, high-level time forecasting, number of invoices, gross book value of PP&E, revenue, balance sheet debt, 3FF.	
6	REWS	27.4	28.7	Capacity utilization, high-level time forecasting.	
7	HR	24.7	25.9	HR case volume, estimated salary by LOB, HR business partners headcount.	
8	Legal	14.7	15.3	High-level time forecasting, 3FF.	
9	PAC	6.3	6.6	High-level time forecasting, donations value.	
10	S&R	7.2	7.5	High-level time forecasting, estimated salary by LOB.	
11	SCM	11.7	12.2	Directly attributable, spend.	
12	TIS	108.3	139.7	Directly attributable, network circuit usage, 3FF.	
13	Benefits	60.3	66.1	Directly attributable, 3FF.	/u
14	Depreciation	20.0	25.6	3FF.	
15	Insurance	15.7	7.3	Operational data and metrics common to the industry.	
16	Total	336.7	377.1		/u

RE: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2022-0200
Certification of Affiliate Relationships Code Compliance

The undersigned, being Enbridge Gas's Vice President, Finance, Tanya Ferguson, in my capacity as an officer of that corporation and without personal liability, hereby certify, to the best of my knowledge, as at the date of certification, that the affiliate costs are in compliance with the Ontario Energy Board's Affiliate Relationships Code for Gas Utilities.

DATED: October 24, 2022, at Toronto, Ontario

ENBRIDGE GAS INC.

[Original Signed By]

Tanya Ferguson

Vice President,
Finance

Supply Chain Management Policy

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DOCUMENT INFORMATION

DOCUMENT TYPE	VERSION NUMBER	EFFECTIVE DATE	FUNCTIONAL OWNER	POLICY MANAGER	POLICY OWNER
Governing Policy	3.4	October 4, 2022	SCM	Manager, SCM Governance	Director, SCM Planning & Governance

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DOCUMENT VERSION HISTORY

VERSION #	DATE	SUMMARY OF CHANGE
1.0	September 17, 2019	Policy created
2.0	April 1, 2020	Major revisions. Revisions to Introduction and Purpose, Excluded Activities, Segregation of Duties, Supplementary Programs, Processes and Procedures, and Roles and Responsibilities
2.1	October 1, 2020	Article 4.0 – Revised to removed reference to Beeline
3.0	April 1, 2021	Article 4.0 – Revised to address materials and services received without an approved Contract in place. Article 4.0 – Addition of approved Non-PO List
3.1	July 5, 2021	Article 4.0 – Revised links to Non-PO approved list
3.2	December 16, 2021	Article 4.0 – Revised links to Non-PO approved list
3.3	June 6, 2022	Article 2.0 – Revised TIS Stewardship Policy to Technology Stewardship Policy and revised link.
3.4	October 4, 2022	Article 2.0 – Revised policy listing and links to remove Corporate Social Responsibility Policy, added Sustainability Policy Article 3.0 – Revised Excluded Activities to include Intercompany agreements Article 4.0 – Revised Enterprise Requirements to include Affiliate Relationships Article 7.0 – Revised Roles and Responsibilities to include affiliates

ENBRIDGE

1. Introduction and Purpose

The Supply Chain Management ("SCM") department is accountable for the procurement, management, and disposition activities for all direct and indirect materials and services that are required to design, construct, operate, and abandon Enbridge assets or to provide services to Enbridge customers ("SCM Activities").

Contravention of this Policy may result in disciplinary action up to and including termination.

2. General

This Policy applies to Enbridge and all of its subsidiaries (including sponsored vehicles) except for those entities and joint ventures that have a separate Supply Chain Management Policy that takes precedence.

This Policy should be read in conjunction with the following policies:

- Authorities and Spending Limits (ASL) Policy;
- Contracts Policy;
- Contingent Workforce Policy, Contingent Workforce Guidelines for People Leaders, and the Contingent Workforce Travel & Expense Policy;
- Enterprise Corporate Card & Business Expense Policy, Rules, Procedures & Guidelines;
- Enterprise Travel Management Policy, Rules, Procedures & Guidelines;
- Indigenous Peoples Policy;
- Records Management Policy;
- Statement of Business Conduct;
- Supplier Diversity Policy;
- Sustainability Policy; and
- Technology Stewardship Policy.

3. Excluded Activities

This Policy does not apply to the following Contracts as defined by the Contracts Policy:

- Contracts necessary to respond to imminent risk of: (i) fatality; (ii) personal injury; (iii) environmental damage; or (iv) significant damage to personal or real property, provided that once such imminent risk is no longer present, this Policy shall apply to such Contract;
- Contracts of a joint venture or other partially owned subsidiary of Enbridge Inc. involving a subject matter for which Enbridge Inc. (or any of its direct or indirect wholly owned subsidiaries) does not have the right or authority (whether directly or indirectly through its representative(s) on the board of directors, management committee, or similar management governing body) to block or otherwise prevent such Contract from being signed by such joint venture;
- Intercorporate services agreements for shared corporate services;
- Assurance Contracts, with the exception of guarantees, surety bonds, or letters of credit that are required or associated with a Supplier Contract;
- Confidentiality Agreements;
- Donations;
- Employee or Director Contracts;

ENBRIDGE

- Energy Marketing, Energy Supply, or Financial Derivative Contracts;
- Insurance policies that are initiated by the Insurance Department;
- Real Estate Contracts except where the purchase or lease of buildings or other real estate presents an opportunity for SCM to provide a cost-effective strategy for Enbridge;
- Scholarships;
- Sponsorships; and
- Treasury Contracts.

4. Enterprise Requirements

- No supply of materials or services may be committed, directed or initiated without engagement of SCM.
- It is not permissible to issue Contracts or Purchase Orders after materials or services have been received. Any invoice received where Contracts or Purchase Orders have not been issued will be considered a direct contravention of this Policy unless the materials or services are on the Non-PO approved list or acceptable per the Enterprise Corporate Card & Business Expense Policy.
- Prior to the initiation of SCM Activities, spending must be approved per the requirements of the Authorities and Spending Limits Policy.
- SCM Activities shall be managed by the SCM department to ensure:
    - Integration and collaboration with key internal and external customers to continuously improve performance and ensure compliance;
    - Optimal purchasing power and value to Enbridge through a systematic approach to acquiring materials and services at competitive costs; and
    - Communication with internal and external customers to advocate for sustainable supply chain solutions and fosters positive relationships with the community through the use of diverse local businesses, and
    - Compliance with (or consideration of) applicable affiliate relationship rules for Supplier Contracts between affiliates.
- Competitive Sourcing
    - Where initial acquisition activities have an estimated contract value of $250,000 or more, a competitive sourcing process must be carried out. Should there be a business reason to forgo a competitive sourcing process, a single/sole source justification must be documented and approved. Applicable affiliate relationship rules must be considered for Supplier Contracts between affiliates and upon request, evidence of compliance must be provided (e.g., paying no more than market price for a service).
- Buying Channels
    - The supply of materials or services shall be committed and procured by SCM using identified and approved buying channels to ensure efficiency in the procurement process.
    - The following are Enbridge's authorized buying channels:
        - Purchase Orders processed through Enbridge's ERP systems, including Maximo. Purchase Orders shall include but not limited to Work Orders, Work Authorization, Work Release Contract, Statements of Work, Service Request Orders, Supplier Catalogue Releases/Orders, Internal Catalogue Releases/Orders, Release/Call-Offs/Orders against Master Agreements, Systems Contract Purchase Orders, Vendor Managed Inventory Orders, blanket/drawdown agreements and Orders, and individual/spot orders;

ENBRIDGE

- Corporate Commercial Cards including, Travel and Entertainment Card / One Card, Fuel Card and Virtual card for those transactions identified in the Enterprise Corporate Card & Business Expense Policy, Rules, Procedures & Guidelines;
- Payment for Non-PO transactions shall only include materials and services on the Non-PO approved list. The list will be updated periodically.

5. Segregation of Duties

Segregation of duties ensures the establishment of internal controls which outline and enforce the SOX legislation requirement that more than one personnel or department be required to complete commercial processes and tasks to prevent the occurrence of errors and/or fraud during the commencement of such transactions. The following functions must be appropriately segregated per transaction:

- Spend Approver;
- Buyer;
- Receiver; and
- Vendor master setup.

Ideally, the Requester, ASL Approver, Buyer, and Receiver/Service Receipt Confirmer functions should all be performed by different individuals. However, in some circumstances two or more of these functions may need to be performed by the same individual as follows:

Requester, Buyer, and Receiver/Service Receipt Confirmer functions may be performed by the same individual, as long as the ASL Approver is segregated. Appropriate controls must be in place to ensure this segregation of duties occurs in the above scenario. If the Buyer performs the Receiver/Service Receipt Confirmer function and enters the confirmation into the respective ERP system on behalf of another individual who received the services, the confirmation or receipt must be supported by written confirmation from the independent individual who actually received the services (email confirmation will suffice).

6. Supplementary Programs, Processes and Procedures

SCM Activities shall be conducted in accordance with the following:

- Category Management & Sourcing Program* – designed to enable both strategic and tactical sourcing activities in a manner that brings optimal value to achieve competitive advantage;
- Contract Management Program* – designed to direct and coordinate the activities necessary to ensure that the supplier(s) and Enbridge fulfill their contractual obligations and reduce risks, while building and maintaining a mutually beneficial relationship(s);
- Procure-to-Pay Program* – outlines the choices and best methods to buy materials and services;
- Materials Management & Logistics Program* – designed to oversee the planning, organizing, controlling and disposition activities principally concerned with the flow of materials into, within, and out of Enbridge; and
- Supplier Management Program* – designed to oversee the assessment, pre-approval, monitoring, and re-evaluation of suppliers, to ensure Enbridge consistently conducts business with those who have the required capabilities, as well as the coordination of supplier surveillance activities at the supplier's facility, prior to shipment and delivery, to ensure only materials that meet the specified standards and requirements are delivered and received.

*The above Programs are the baseline of how SCM conducts its activities and will continuously be reviewed and improved by means of working sessions and other related tools.

7. Roles and Responsibilities

The internal customer / end user of SCM Activities is responsible for:

- Partnering with SCM in the management of supplier relationships;

ENBRIDGE

- Providing SCM with all technical requirements for the material(s) or service(s) to be acquired, including but not limited to: scope of work, specifications, drawings, safety and quality requirements;
- Obtaining approval for the spend per the requirements of the Authorities and Spending Limits Policy;
- Engaging SCM within reasonable lead time for material or service requirements;
- Approving the contracting strategy (including evaluation criteria) as required;
- Partnering with SCM in the evaluation, negotiation and selection of suppliers;
- For services, the overseeing and managing the execution of work; and
- Validating, in a timely manner, receipt of the contracted quality and quantity of material(s) or service(s).

The SCM Department is responsible for:

- Performing strategic sourcing, supplier relationship management, contract development and administration, procurement, logistics and materials management (i.e., issuance of RFX, evaluation of proposals, negotiation with suppliers, selection of suppliers, issuance of contracts, administration of contracts, claims management, etc.);
- The management of suppliers of activities through their lifecycle (i.e., supplier assessment, pre-approval, reevaluation and termination);
- Acquisition and contract administration (i.e., delegated by a Contract Owner); and
- Review and approval of Supplier Contracts* as a Core Functional Department as defined in the Contracts Policy when:
    - A proposed Preliminary Agreement, Confidentiality Agreement or RFX is to be utilized by a Contract Owner;
    - All proposed Supplier Contracts*;
    - An Amendment modifies or supplements the terms or conditions of an Existing Approved Contract; and
    - A proposed Contemplated Contract Supplement issued under an Existing Approved Contract that is a Supplier Contract.

The review and approval thresholds will be as provided in the ASL Policy.

* “Supplier Contract” means a legal agreement between Enbridge and its third-party vendors, affiliates, suppliers and service providers for the procurement, management and disposition of materials and services subject to prescribed terms and conditions. These activities include but are not limited to, RFX’s; materials and services; construction; and consulting activities, with the exception of transactions that have been expressly excluded from this Policy.

The Executive Leadership Team

- Each Enbridge Executive Leadership Team member is responsible for ensuring compliance with this Policy within such individual’s areas of management responsibility.
- Exceptions to the provisions of this Policy must be approved by the Vice President and Chief Supply Chain Officer

R Recommend | A Agree | P Perform | I Input | D Decide

	SCM	Internal Customer / End User
Definition of scope of w ork	I	P
Decide on scope of w ork and specifications	I	D
Approval of spend	I	D
Develop contract strategy	P	I
Approve contracting strategy (incl. evaluation criteria)	R	D
Issue RFx	P	I
Evaluate, negotiate and select supplier*	D	A
Issue contract	P	I
Oversee services provided by supplier	I	P
Administer contract and manage claims	P	D

RAPIDs for SCM decisions

*Notes:

In the specific situation where a sourcing steering committee has been formed as part of the sourcing strategy, the supplier selection decision can be made by the sourcing steering committee.

In situations where the Internal Customer / End User does not agree with the supplier selection per the pre-determined evaluation criteria, they may obtain approval from a member of their ELT to select an alternate supplier.

ENBRIDGE

Authorities and Spending Limits Policy

Policy management:		
	Title	**Name**
Policy Preparer	Chief Accounting Officer	Pat Murray
Policy Owner	Chief Financial Officer	Colin Gruending
Policy Approver	Enbridge Inc. Board of Directors	

Policy version control:		
Version	Approval Date	Effective Date
6.0	July 26, 2021	June 8, 2021

Contents

1. Executive Summary

By law, the Board has the duty and power to oversee the management of the business and affairs of the Company and may delegate authority to officers and certain other individuals to act on behalf of the Company. The Authorities and Spending Limits ("ASLs") set out within this Policy ("Policy") utilize a risk-based approach of delegating authority to approve ASL Transactions on behalf of the Company (including on behalf of its Applicable Subsidiaries and Applicable Joint Ventures) to Enbridge employees (and approved contractors) at specified salary grade levels. Enbridge employees and contractors are required to obtain the appropriate approvals pursuant to this Policy prior to undertaking any ASL Transaction on behalf of the Company or its Applicable Subsidiaries or Applicable Joint Ventures. Any ASL Transactions of the Company or its Applicable Subsidiaries or Applicable Joint Ventures in excess of the ASLs set forth in this Policy must be approved by the Board.

2. Purpose

This Policy applies to ASL Transactions undertaken by the Company and its Applicable Subsidiaries and Applicable Joint Ventures and is intended to establish levels of control and accountability over the approval of such ASL Transactions. This Policy does not apply to ASL Transactions undertaken by U.S Subsidiaries or U.S Joint Ventures. U.S. Subsidiaries and U.S. Joint Ventures have a separate ASL policy that takes precedence, which should be consulted in connection with the approval of any ASL Transactions proposed to be undertaken by or on behalf of such entities.

3. Other Enbridge Policies

This Policy should be read in conjunction with the following policies:

- Capitalization Policy – provides guidelines with respect to classification of capital and operational expenditures;
- Community Investment and Employee Engagement Policy – provides guidance regarding charitable and political donation approval;
- Contracts Policy – outlines (i) all internal review and approval requirements that must be satisfied prior to the signing of a proposed Contract by Enbridge; (ii) which individuals are authorized to sign a proposed Contract on behalf of Enbridge; and (iii) the responsibilities within Enbridge as to administration of a Contract after it is executed;
- Enterprise Corporate Card & Business Expense Policy – provides guidance regarding employee expense approval;
- Financial Risk Management Policy – governs the approval and execution of financial risk management transactions;
- Applicable Human Resources Policies and Hiring Approval Guidelines – provides guidance regarding execution and approval of employment contracts; and
- Treasury Policy – governs financing and cash management transactions.

The approval, execution and related payment of Treasury (financing and cash management) and Risk Management transactions and Contracts that are within the scope of the Treasury Policy or the Financial Risk Management Policy are governed by such policies; the authority limits set forth in such policies will supersede the authority limits set out in this Policy for all such transactions and Contracts.

The approval of employment Contracts is governed by the Applicable Human Resources Policies and Hiring Approval Guidelines; the approval requirements set forth in such policies will supersede the authority limits set out in this Policy.

The approval of employee expenses is governed by the Enterprise Corporate Card & Business Expense Policy; the authority limits set forth in such policy will supersede the authority limits set out in this Policy.

The following transactions have specific approval requirements and are outside of the scope of this Policy:

- Audit fees – Initially approved by the Board with subsequent Standard Transactions and Contracts to be approved by the CFO or designee; and
- Legal settlements – Approved by an EVP or VP of Law or designee.

4. Definitions

Acquisition – The purchase of an ownership interest in an entity or of a significant asset from a non-Enbridge person or entity.

Allowance for Funds Used During Construction (AFUDC) – An accounting convention that represents the estimated costs of financing construction projects, which consists of an equity component and an interest component.

Applicable Joint Ventures – Joint Ventures of the Company, excluding U.S. Joint Ventures.

Applicable Subsidiaries – Subsidiaries of the Company, excluding U.S. Subsidiaries.

ASLs – Defined in *Section 1 – Executive Summary*.

ASL Transactions – Transactions requiring approval under this Policy, including operating commitments and expenditures; capital commitments and expenditures; Capital Projects; Development Expenditures; AFEs; Standard Transactions; Acquisitions, Dispositions, and Contracts (including Inflow Contracts). A single ASL Transaction includes the initiation of the transaction through to payment, unless the ERP is configured to match the transaction to a preceding transaction that was approved pursuant to this Policy, within tolerance.

Authorization for Expenditure (AFE) – Spending for a Capital Project or Development Expenditures that has been approved (a) by the Board or (b) by management with the appropriate ASLs under this Policy, which can be committed to a third party.

Board – Enbridge Inc. Board of Directors.

Budget – The budget of the Company and its Subsidiaries, as approved annually by the Board and updated from time to time.

Budgeted Spending – Any and all operating commitments or expenditures and capital commitments or expenditures that have been *previously* approved (a) by the Board or (b) by management with the appropriate ASLs under this Policy. Once Unbudgeted Capital Spending is approved (a) by the Board or (b) by management with the appropriate ASLs under this Policy, it is considered Budgeted Spending.

CAO – The Chief Accounting Officer of the Company.

Capital Project – A project that qualifies as one of the following:

- Growth Project: A project requiring enhancements to the system, which extend the life of the system, enhance the service capability of the existing assets, increase capacities from existing levels, and/or reduce costs or enhance revenues.
- Maintenance Capital Project: A project requiring expenditures on existing assets that are necessary to maintain the service capability of the system (e.g., the replacement of equipment which is completing its useful life).
- Enhancement Project: A project requiring improvements to the system in response to developing industry standards and/or government regulations.

Capitalized Interest – The cost of borrowing to construct a Capital Project.

CFO – The Chief Financial Officer of the Company.

Company – Enbridge Inc.

Contract – An agreement between two or more entities and/or persons that contains rights and obligations of the parties that are enforceable under law. Contracts are governed by both this Policy and the Contracts Policy.

Development Expenditures – Any and all commitments or spending related to the development or pursuit of a Capital Project before it meets the capitalization criteria as defined by the Capitalization Policy.

Disposition – The sale or other divestiture to a non-Enbridge person or entity of an ownership interest in an entity or of a significant asset.

Enbridge – collectively, the Company and all of its Subsidiaries.

ERP System – Enbridge enterprise resource planning system (i.e., Oracle or SAP).

Inflow Contract – A revenue or other cash inflow contract that results in a collection of revenue or other cash by Enbridge. Contracts effectuating Dispositions do not constitute “Inflow Contracts” under this Policy.

Joint Venture – With respect to an entity, any corporation, partnership (general or limited, including master limited), limited liability company, trust, unincorporated organization, or other entity or association that is directly or indirectly partially owned, but not wholly owned, by Enbridge.

Operating Segments – Enbridge’s business segments as defined in its financial statements.

Policy – Defined in *Section 1—Executive Summary*.

Salary Grade – The grade associated with an individual’s salary band and used to identify his or her job level, as identified by Enbridge Human Resources and recorded in Workday.

Standard Transactions – Transactions in the normal course of business initiated through one of the following methods:

- Invoice: Commercial document that itemizes and records a transaction between a buyer and a seller;
- Payment Requisition: Initiated to authorize payment of an obligation that has not been previously authorized by a Purchase Order where there will not be an invoice issued for the expenditure (also referred to as a cheque requisition);
- Purchase Order: Commercial document issued from the ERP System (by Enbridge) to a seller indicating types, quantities, and prices for products/materials;
- Purchase Requisition: Internal document initiated in the ERP System and sent to Supply Chain Management indicating types, quantities, and prices for goods or services; or
- Work Order: Commercial document issued from the ERP System (by Enbridge) to a seller indicating types, quantities, and prices for services.

A Contract is not a Standard Transaction as the Contracts Policy also applies to Contracts.

Subsidiary – With respect to an entity, any corporation, partnership (general or limited, including master limited), limited liability company, trust, unincorporated organization, or other entity or association that is directly or indirectly wholly owned by Enbridge.

Unbudgeted Capital Spending – Any and all capital commitments or spending incurred on Capital Projects or related to transactions categorized as capital (as defined in the Capitalization Policy) that either (a) have not been previously approved (i) by the Board or (ii) by management with the appropriate ASLs under this Policy or (b) are in excess of the approved Budget (e.g., the Capital Project was approved by the Board, but the amount is expected to exceed the budgeted amount). For purposes of this Policy, Acquisitions, Dispositions and Development Expenditures are categorized as Unbudgeted Capital Spending. Once Unbudgeted Capital Spending is approved under this Policy, it is considered Budgeted Spending.

Unbudgeted Operational Spending – Any and all operational commitments or spending (as defined in the Capitalization Policy) in excess of the Operating Segment annual budget.

U.S. Joint Ventures – Joint Ventures of the Company formed and existing under the laws of the United States.

U.S. Subsidiaries – Subsidiaries of the Company formed and existing under the laws of the United States.

5. General

5.1 Application to Employees and Contractors

Enbridge employees (and approved contractors) must only approve ASL Transactions (a) that fall within the roles and responsibilities included in their job description and (b) for which they have the appropriate ASLs (as outlined within this Policy).

Enbridge employees who have a Salary Grade of E510 or higher will automatically be granted Standard ASLs. Elevated ASLs or Unique Transaction ASLs, above Standard ASLs, may be requested or automatically granted in certain circumstances (*i.e*., Projects Elevated ASLs and Supply Chain Management Elevated ASLs).

Contractors will not automatically be granted Standard ASLs and will be required to request ASLs for the approval of Standard Transactions using the Elevated ASL Process.

Any desired reductions in ASLs for employees (or approved contractors) must be implemented and enforced by the applicable business group and will not be incorporated into or enforced by this Policy.

5.2 Breaches and Exceptions

All Enbridge employees and contractors are responsible for being familiar with and complying with this Policy. All aspects of non-compliance must be reported to the employee's immediate supervisor and, as appropriate, to an employee in a higher Salary Grade in the business unit or to the CAO or Enbridge's Ethics & Compliance Department.

Non-compliance with this Policy constitutes a violation of the Enbridge Statement on Business Conduct and may result in disciplinary action. A summary of all incidents of non-compliance with, or breaches of, this Policy will be compiled by the Chief Accounting Office. Any material non-compliance incidents or breaches will be reported to the CFO and may result in additional sanctions up to, and including, termination.

All instances of approving an ASL Transaction above management's ASLs under this Policy must be documented, approved in accordance with this Policy as soon as practicable, and promptly reported to the Chief Accounting Office. In extreme circumstances related to the protection of the environment, maintenance of health and safety of employees and the public, or in other emergencies, and when the Chief Accounting Office cannot be notified, employees should exercise prudence and judgment in exceeding their ASLs under this Policy.

A Policy exception may be requested from Policy requirements that are not feasible for a business group for a specified period. The Policy Exception Form must be completed indicating the business reason for the policy exception, the risks associated with the exception and mitigating actions being taken to lessen the risk. This must be approved by the business group's Director and VP prior to submission to the Chief Accounting Office for approval. The Chief Accounting Office is responsible for reporting to the CFO exceptions arising from Enbridge's activities governed by this Policy.

5.3 Governance

This Policy applies to ASL Transactions undertaken by or on behalf of the Company and its Applicable Subsidiaries and Applicable Joint Ventures.

a. The Company

By law, the Board has the duty and power to oversee the management of the business and affairs of the Company and may delegate certain of these duties and powers to officers and certain other individuals. By adoption of this Policy, the Board hereby delegates to officers, employees, and approved contractors of Enbridge the authority to approve ASL Transactions on behalf of the Company, subject to the ASLs set forth herein and the overarching authority of the Board.

Any ASL Transactions of the Company in excess of the ASLs under this Policy must be approved by the Board.

b. Applicable Subsidiaries

The duty and power to oversee the management of each Subsidiary of the Company resides with the applicable governing body of such Subsidiary. In addition to any approvals obtained pursuant to this Policy, material ASL Transactions undertaken by Applicable Subsidiaries with their own board of directors, management committee, or equivalent may require additional approval by the Subsidiary's governing body. Please contact the Corporate Secretarial Department to determine what, if any, such approvals are required.

c. Applicable Joint Ventures

The duty and power to oversee the management of each Joint Venture of the Company resides with the applicable governing body of such Joint Venture. Certain Joint Ventures may adopt their own ASL policies (or may be party to operating or other agreements that address ASLs) and may require that representatives of the Joint Venture comply with the ASLs set forth in such policies or agreements.

In addition to any obligations to comply with such policies or agreements, Unbudgeted Capital Spending ASLs apply to any ASL Transaction of an Applicable Joint Venture that could affect Enbridge's capital (e.g., the acquisition of ownership interests in the Joint Venture, or approval of a Capital Project or Development Expenditure that could affect a planned or expected dividend to be paid to Enbridge from the Applicable Joint Venture) unless there was prior, specific approval of the ASL Transaction included within the Company's Budget. In that case, Standard ASLs would apply. The applicable ASLs are applied to the value of the ASL Transaction based on the percentage of the Joint Venture that Enbridge owns (e.g., if Enbridge owns a 50% share of a Joint Venture that is approving a $100M Capital Project, the ASL Transaction would be valued at $50M ($100M x 50%)). Approval of capital contributions to an Applicable Joint Venture are out of scope of the ASL Policy as they are governed by the Treasury Policy.

At the judgement of Enbridge's representatives of the Applicable Joint Venture, additional approvals should be obtained for significant items that do not affect Enbridge's capital (e.g., significant Capital Project, long-term Contract or annual budget of a self-funding Joint Venture).

For those Applicable Joint Ventures where Enbridge is the operator and is responsible for the AFEs and Standard Transactions of the Joint Venture, after the aforementioned ASL approvals have been obtained, Standard ASL applies to either:

- the value based on the percentage of the Joint Venture that Enbridge owns (e.g., if Enbridge owns a 50% share of a Joint Venture that is approving a $10M Purchase Order, the Standard Transaction would be valued at $5M ($10M x 50%)); or
- 100% of the dollar value of where required by the ERP System (e.g., if Enbridge owns a 50% share of a Joint Venture that is approving a $10M AFE, the ERP system may require that the AFE be approved for $10M (100% of the transaction value)).

In addition to any approvals obtained pursuant to this Policy, certain ASL Transactions undertaken by Applicable Joint Ventures may require additional approval by the Joint Venture's governing body. Please contact the Chief Accounting Office or the attorneys who manage the Joint Venture agreements to determine what, if any, such approvals are required.

5.4 ASL Delegation

An individual may not delegate his or her higher ASLs to an individual with lower ASLs.

5.5 Valuation of ASL Transactions

ASLs must be applied on a transactional basis to the aggregate value of the ASL Transaction. Transactions must not be disaggregated to avoid higher approval requirements.

If, following approval of an ASL Transaction (other than a Capital Project), there is an increase to the value of the ASL Transaction, the ASL Transaction must be reapproved based upon the aggregate value of the ASL Transaction following the increase.

If, following approval of a Capital Project, there is a change to the value of the Capital Project that will result in the Budgeted Spending for the Capital Project being exceeded, the incremental spending constitutes Unbudgeted Capital Spending, and the amount of the incremental spending must be approved applying Unbudgeted Capital Spending ASLs.

Budgets for Capital Projects or AFEs should include AFUDC or Capitalized Interest in the amounts presented for approval. Changes or cost overruns as a result of actual AFUDC or Capitalized Interest charges compared to the approved Budgets for Capital Projects or AFEs require approval under this Policy.

5.6 Acquisitions

Acquisitions are valued based on the higher of the consideration paid by Enbridge (*i.e.*, the purchase price or the value of the consideration exchanged) or net book value. For purposes of this Policy, Acquisitions are categorized as Unbudgeted Capital Spending, and Unbudgeted Capital Spending ASLs apply.

5.7 Dispositions

Dispositions are valued based on the higher of the sales price received by Enbridge or net book value. For purposes of this Policy, Dispositions are categorized as Unbudgeted Capital Spending, and Unbudgeted Capital Spending ASLs apply.

5.8 Contracts

a. Contracts and the Contracts Policy

Pursuant to the Contracts Policy, before a proposed Contract is executed on behalf of Enbridge, the Contract Owner (as defined in the Contracts Policy) must obtain Contract approvals in accordance with the Contracts Policy. Per the Contracts Policy, the Contract must be approved by the Board *or* by an individual with appropriate ASLs in accordance with this Policy. Once a proposed Contract has been approved, execution of Contracts is governed by the Contracts Policy. Any Standard Transactions initiated under the Contract require subsequent approval(s) applying this Policy.

The ASLs set forth in this Policy do not apply to individuals providing Core Functional Department Review under the Contracts Policy (e.g., to individuals providing approval on behalf of the law department or tax department).

b. Valuation of Contracts

For purposes of applying this Policy, the dollar value of a Contract shall equal a good faith estimate of the aggregate legally committed payments by (or to) Enbridge during the Contract term at the time of signing. The dollar value of the Contract should include any payments that may be required upon satisfaction of conditions Enbridge has no control over but exclude any obligations under a Contract that are not directly related to payments.

c. Valuation of Non-monetary Contracts

A non-monetary contract is a Contract that does not include any legally binding obligations or rights of Enbridge that are directly related to payments *and* an estimate of future payments cannot be made. Examples of non-monetary Contracts include, without limitation, a confidentiality agreement, a letter of intent, a memorandum of understanding, or a master services agreement.

For purposes of this Policy, a non-monetary Contract shall be deemed to have a dollar value of $5M unless any lawyer in the Law Department responsible for providing advice with respect to a non-monetary Contract, or the CAO, determines that such Contract has either a higher or lower dollar value than $5M. To approve a Non-Monetary Contract under this Policy, Standard ASL applies (unless Elevated ASL or Unique Transaction ASL has been granted and is appropriate to be applied in the circumstance).

d. Long-term Contracts

In the event that a single Contract (Inflow Contract or expenditure) has a term greater than three years and the dollar value of the Contract is greater than $150M, the Contract must be approved by the Board, unless:

- the Contract relates to a Board-approved Capital Project, in which case the Contract may be approved by management with the appropriate ASLs under this Policy (i.e. Standard ASLs, Inflow Contracts Elevated ASLs or Elevated Projects ASLs); or
- the Contract relates to a revenue renewal or re-contracting, is in the normal course of business, has no unusual rates or features (e.g., unprecedented discount, unusual rate structure, abnormal Contract term) and relates to existing infrastructure, in which case the Contract may be approved by management applying the Inflow Contracts Elevated ASLs; or

- the Contract relates to the purchase of power and/or drag reducing agent (DRA), is in the normal course of business for ongoing needs of a business unit, has no unusual features such as assumption of significant asset of entity ownership (e.g., power plant ownership interest, ownership of a Joint Venture), and has a term of 5 years or less, in which case the Contract may be approved by management applying Standard ASLs.

5.9 Foreign Currency

The ASLs noted in dollars throughout this Policy refer to both Canadian dollars (CAD) and U.S. dollars (USD). No translation is required between Canadian and U.S. dollars (i.e., a parity foreign exchange rate is assumed). For greater certainty, for ASL Transactions by legal entities incorporated in Canada, the limits are expressed in Canadian dollars and for ASL Transactions by legal entities formed in the United States, the limits are expressed in U.S. dollars.

Specific ASLs are also included in Euros (EUR) and Great British Pounds (GBP) for transactions of Enbridge's Subsidiaries and Joint Ventures that are incorporated in Europe and the United Kingdom.

For transactions denominated in currencies other than CAD, USD, EUR or GBP, the associated ASLs are determined by translating to the functional currency (CAD or USD) of the transacting entity at the spot foreign exchange rate at the date of the transaction. If a transaction occurs in GBP or EUR within a legal entity that is not incorporated in the United Kingdom or Europe, then ASLs will be determined by translating to the functional currency (CAD or USD) of the transacting entity at the spot foreign exchange rate at the date of the transaction.

6. Standard ASLs

Standard ASLs, as follows, apply to the ASL Transactions discussed in more detail below.

Standard ASLs							
Salary Grade	N/A	E900 series	E800 series	E800 series	E700 series	E600 series	E510
Illustrative management title	CEO	EVP/ SVPs reporting to CEO	SVP/VP with VP reports	VP	Director	Manager	Supervisor
Standard ASLs – CAD or USD	Unlimited	Unlimited	$50M / Unlimited[1]	$25M	$5M	$1M	$250K
Standard ASLs – GBP	Unlimited	Unlimited	£30M	£15M	£3M	£600K	£150K
Standard ASLs – EUR	Unlimited	Unlimited	€30M	€15M	€3M	€600K	€150K

6.1 Budgeted Spending

Standard ASLs apply to ASL Transactions that qualify as Budgeted Spending (unless Elevated ASL or Unique Transaction ASL has been granted and is appropriate to be applied in the circumstance).

6.2 Unbudgeted Operational Spending

Standard ASLs apply to ASL Transactions that qualify as Unbudgeted Operational Spending; however, material Unbudgeted Operational Spending (including multi-year commitments) will be taken for Board approval at the judgement of senior management. Additionally, if the operating budget by Operating Segment is expected to materially exceed the Budget approved by the Board for the year, then senior management must notify the Board accordingly.

[1] SVPs and VPs with VP Reports have unlimited Standard ASLs for Budgeted Spending only; the transactional limit of $50M applies to Unbudgeted Operational Spending.

7. Unbudgeted Capital Spending ASLs

The following Unbudgeted Capital Spending ASLs apply to ASL Transactions that qualify as Unbudgeted Capital Spending:

Unbudgeted Capital Spending ASLs							
Salary Grade	N/A	E900 series	E800 series	E800 series	E700 series	E600 series	E510
Illustrative management title	CEO	EVP/ SVPs reporting to CEO	SVP/VP with VP reports	VP	Director	Manager	Supervisor
Unbudgeted Capital Spending ASLs – CAD or USD	$150M	$10M	$5M	$5M	$1M	$200K	None
Unbudgeted Capital Spending ASLs – GBP	£90M	£6M	£3M	£3M	£600K	£120K	None
Unbudgeted Capital Spending ASLs – EUR	€90M	€6M	€3M	€3M	€600K	€120K	None

At each regularly scheduled meeting of the Board, management must present to the Board the aggregate of the enterprise-wide Unbudgeted Capital Spending approved by management on behalf of the Company, its Subsidiaries and Joint Ventures for individual items greater than $5M. **Cumulative Unbudgeted Capital Spending for the Company, its Subsidiaries and Joint Ventures within the period between Board meetings must not exceed $400M.** If deemed appropriate, the Board will ratify the Unbudgeted Capital Spending and reset management's delegated authority.

Unbudgeted Capital Spending is tracked and accumulated by the Corporate Financial Planning & Analysis team. If proposed Unbudgeted Capital Spending would (a) exceed the individual Unbudgeted Capital ASLs under this Policy or (b) exceed management's cumulative $400M Unbudgeted Capital Spending limit for the Company, its Subsidiaries and Joint Ventures within the period, approval of the Board must be obtained.

If any particular item of Unbudgeted Capital Spending is greater than $10M, the nature and economics of the Capital Project must be approved by the CEO and reported to the Board.

For Capital Projects with Development Expenditures exceeding one-year, cumulative Development Expenditures, by Capital Project, must be reported to the CEO at least annually in a manner prescribed by the CAO.

The following guidance is also applicable to all Unbudgeted Capital Spending:

- Substitutions within or between an Operating Segments' Maintenance Capital Project or Enhancement Project budgets can take place with the approval of the executive leader of the Operating Segment.
- Substitutions between Growth Projects budgets are prohibited except for regulated gas distribution entities. The use of approved Growth Project budgets to supplement Maintenance Capital and Enhancement Project budgets is also prohibited.

Once Unbudgeted Capital Spending is approved (a) by the Board or (b) by management with the appropriate level of ASL under this Policy, it is considered Budgeted Spending, and Standard ASLs apply to the approval of any ASL Transactions related to the Capital Project (unless Elevated ASL or Unique Transaction ASL has been granted and is appropriate to be applied in the circumstance).

8. Elevated ASLs

8.1 Overview

Elevated ASLs are increases to Standard ASLs, which will automatically be provided to employees within select groups for certain types of ASL Transactions and which may be granted to certain individual employees or contractors upon request, as outlined below.

Elevated ASL requests for individual employees and contractors must be justified by the job requirements and supported by a demonstrated excessive level of approval requests being passed on to their direct supervisor. Elevated ASL requests must be approved by a departmental VP, and final approval will be granted by the Chief Accounting Office.

The Chief Accounting Office will conduct an annual review of employees and contractors with Elevated ASLs, which will be verified by the applicable VPs.

8.2 Projects Elevated ASLs

Given the capital-intensive nature of the projects that are undertaken by the Projects Groups, all employees within the Project Groups are hereby automatically granted Elevated ASLs, as set forth below, to approve ASL Transactions related to Budgeted Spending:

Projects Elevated ASLs						
Salary Grade	E900 series	E800 series	E800 series	E700 series	E600 series	E510
Illustrative management title	EVP/ SVPs reporting to CEO	SVP/VP with VP reports	VP	Director	Manager	Supervisor
Elevated Budgeted Spending ASLs	Unlimited	Unlimited	$50M	$25M	$5M	$1M

8.3 Supply Chain Management Elevated ASLs

All employees within the Supply Chain Management Group are hereby automatically granted Elevated ASLs, as set forth below, to approve procurement-related ASL Transactions for the entire enterprise; provided, that the Supply Chain Management Group may only utilize such Elevated ASLs where the underlying ASL Transaction has been approved (a) by the Board or (b) by an individual within the business unit under this Policy.

Supply Chain Management Elevated ASLs										
Salary Grade	E900 series	E800 series	E800 series	E700 series	E600 series	E510	E500	E420	E410	E400
Illustrative management title	EVP/ SVPs reporting to CEO	SVP/VP with VP reports	VP	Director	Manager	Supervisor	Team Lead	Senior Buyer	Buyer	Junior Buyer
Elevated Authority to commit	Unlimited	Unlimited	Unlimited	$100M	$25M	$5M	$1M	$500K	$250K	$250K

8.4 Inflow Contracts Elevated ASLs

All employees are hereby automatically granted Elevated ASLs, as set forth below, to approve the execution of budgeted or unbudgeted Inflow Contracts.

Inflow Contracts Elevated ASLs							
Salary Grade	N/A	E900 series	E800 series	E800 series	E700 series	E600 series	E510
Illustrative management title	CEO	EVP/ SVPs reporting to CEO	SVP/VP with VP reports	VP	Director	Manager	Supervisor
Inflow Contracts ASLs – CAD or USD	Unlimited	Unlimited	\$150M / Unlimited[2]	\$50M	\$25M	\$5M	\$1M
Inflow Contracts ASLs – GBP	Unlimited	Unlimited	£90M	£30M	£15M	£3M	£600K
Inflow Contracts ASLs – EUR	Unlimited	Unlimited	€90M	€30M	€15M	€3M	€600K

9. Unique Transaction ASLs

Unique Transaction ASLs may be requested for certain types of distinctive transactions (e.g., natural gas procurement payments, facilities leases, regular settlements with Enbridge's credit card providers, etc.) to ensure business can be transacted as efficiently as possible.

Unique Transaction ASL requests must be approved by a departmental VP, and final approval will be granted by the Chief Accounting Office. The Chief Accounting Office will conduct an annual review of employees and contractors with Unique Transactions ASLs, which will be verified by the applicable VPs.

10. Policy administration

The ASLs set forth in this Policy will be primarily managed through the applicable ERP System and its related applications. The Policy Owner is responsible for the overall administration of this Policy. The Policy Owner in consultation with the Policy Preparer is responsible for ensuring periodic reviews are conducted of the ASLs and this Policy. The Policy Owner is responsible for regularly reporting to the Board on significant matters arising from activities governed by this Policy.

Any requests for revisions of this Policy are to be submitted to the Chief Accounting Office for consideration. Any approved requests will be reviewed with the Policy Owner.

Any amendments to this Policy must be approved by the Board except for the following, which may be approved by the CFO:

- Changes in the ASLs for VPs and below;
- Annual updates to the ASLs denoted in GBP and EUR for Enbridge legal entities incorporated in United Kingdom or Europe;
- Addition or deletion of Elevated ASL requirements;
- Addition or deletion of Unique Transaction ASL scenarios and associated limits; and
- Amendments to correct errors, clarify meaning or intent or with respect to the administration of this Policy.

[2] SVPs and VPs with VP Reports have unlimited Inflow Contracts Elevated ASLs for Budgeted Inflow Contracts only; the transactional limit of \$150M applies to Unbudgeted Inflow Contracts.

Request for Proposal, Request for Quotation & Request for Information Authorized Contract Template User Guide

January 24, 2019

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USER GUIDE for the RFx (RFP, RFQ, or RFI) Authorized Contract Templates (ACTs)

PURPOSE

This User Guide will help you successfully use an ACT to create a RFx. This document does not provide guidance on strategic sourcing principles or whether a RFx should be created, which is a Supply Chain Management (SCM) decision.

NOTE: **The RFx ACTs replace all "Standard Contracts" or "Approved Contract Templates" for RFxs previously approved or granted under a predecessor Contracts Policy of either Enbridge Inc. or Spectra Energy Corp. (or any of their respective subsidiaries).**

INTRODUCTION

The term "RFx" captures multiple procurement processes. This User Guide offers additional considerations for creating a RFx. At Enbridge, the following RFx processes have associated ACTs:

RFx TYPE	THIS PROCESS IS USED TO …
1. Request for Information (RFI)	• acquire more information before you can proceed to a more formal request. • find out more information about a supplier, their capabilities, experiences, and/or services or goods. NOTE: A RFI is usually an initial process used in combination with a RFP or a RFQ. This should not be confused with the request for information process set out in a contract when seeking further information from the supplier during the execution of a contract.
2. Request for Proposal (RFP)	• solicit a proposal from one or more suppliers that will propose the best solution for goods or services to respond to an issue or meet a specific need. • seek both technical and commercial responses from suppliers.
3. Request for Quotation (RFQ)	• determine the goods and/or service requirements for procurement. • obtain pricing for such goods and/or services. NOTE: A RFQ should not be used to request technical information.

The RFx processes may be used ***alone*** (e.g. you issue a RFP as your procurement process) or in ***combination*** (e.g. you issue a RFI, followed by a RFP, followed by a RFQ).

NOTES:

The determination of appropriate RFx process(es) is driven by business objectives. Once business objectives are clearly identified, determine the applicable procurement process(es) based on the description of each RFx process above.

If you are unsure which procurement process(es) to use, contact your People Leader.

Before you begin, review this User Guide in detail to ensure you consider all relevant provisions.

WHEN DO I USE THE RFx ACTs?

These ACTs should only be used if **both** of the following conditions apply:

(a) You have determined which RFx is applicable to your procurement.

(b) You are a member of the **SCM Department** or a designate of the SCM Department.

NOTE: If you are not a member of the SCM Department, (even if you use the RFx ACT), **you must seek review and approval of the RFx by the Law Department and the SCM Department.**

BEFORE COMPLETING A RFx

1. EXISTING AGREEMENTS (Applicable to RFQ and RFP Only)

Determine if there are existing agreements with the Respondent(s)/Proponent(s). If so, establish whether the existing agreements:

(a) cover the RFQ/RFP subject;

(b) can be used in the jurisdiction where the goods and/or services are procured (e.g. you cannot use a US only agreement for Canadian procurement);

(c) can be utilized for the Company issuing the RFQ/RFP (e.g. a legacy Spectra contract may not be used for Enbridge entities in some cases); and

(d) have not expired.

NOTES:

If there is an existing agreement, the Terms & Conditions (T&Cs) of the existing agreement will apply to the procurement. No exceptions are allowed by the Respondent/Proponent that deviate from the T&Cs set out in the existing agreement.

As part of the RFP/RFQ process, the Company may impose additional conditions, such as increased or amended insurance requirements.

2. CONFIDENTIALITY

(a) For RFPs/RFQs only, if the Respondent/Proponent has an existing agreement, the Respondent/Proponent's obligations with respect to Company confidential information are governed by the existing agreement.

(b) If the Respondent/Proponent does not have an existing agreement (or if an RFI is being issued where there will be Company confidential information in the RFI documents), the following documents must be completed prior to the RFx documents being sent to the Respondent/Proponent.

i. **NOT USING MERX**: Follow the instructions in APPENDIX 4 of this User Guide to complete the Non-MERX Confidentiality Undertaking to provide to the Respondent/Proponent.

> **NOTE**: The Respondent/Proponent must provide a signed copy of the Non-MERX Confidentiality Undertaking to the RFx Contact ***before*** the RFx documents are sent to the Respondent/Proponent. No exceptions by the Respondents/Proponents to the Non-MERX Confidentiality Undertaking should be considered.

ii. **USING MERX**: Append the MERX Confidentiality Undertaking as instructed in APPENDIX 5 of this User Guide.

HOW TO COMPLETE A RFx ACT

ASSEMBLE THESE DOCUMENTS:

- RFx ACTs, including Appendices; and
- this User Guide

NOTE: All of these documents are located in the SCM Governance Documents Library.

DOWNLOAD THE RFx ACT

1. Download the applicable RFx ACT from the SCM Governance Documents Library.

NOTE: To ensure you are using the latest version, ***always*** download a new copy of the ACT.

PREPARE THE RFx ACT

2. Complete all items highlighted in grey on the ACT.

   Specific step-by-step instructions for completing each RFx ACT are described in following Appendices:

   (a) Appendix 1 – Guidance for Using the RFP ACT

   (b) Appendix 2 – Guidance for Using the RFQ ACT

   (c) Appendix 3 – Guidance for Using the RFI ACT.

3. Remove all the “Notes to Preparer” language from the ACT.

NOTE: ONLY the following can be altered on the ACT:

- Items highlighted in grey within square brackets “[ ]”.
- Areas with instructions via “Note to Preparer”.

Any other changes to the language in the ACT require review and approval by the Law Department.

FINALIZE THE RFx ACT

4. Review the ACT to ensure that all required fields have been completed and all “Notes to Preparer” have been removed. **Hint** - Perform a search for square brackets, i.e. “[“.

5. Complete a spelling and grammar check.

6. Ensure that all RFx Appendices and associated attachments to the RFx are present and in the correct order.

NOTE: If the aggregate value of the RFx is greater than **$2,000,000**, approval by the Law Department is required before issuing the RFx.

NEED HELP?

- If you have questions throughout this process, contact SCM Governance at SCMPolicy@enbridge.com.
- If you are unsure what information to enter into a RFx ACT, contact the Law Department.

APPENDIX 1 – GUIDANCE FOR USING THE RFP ACT

STRUCTURE OF RFP

Each RFP prepared from the ACT is comprised of the following documents:

- Instructions to Proponents;
- RFP Data Sheet;
- Appendix A – Proposal Format and Submission;
- Appendix B – Proposal Submission Acknowledgment Form;
- Appendix C – Technical Requirements Document;
- Appendix D – Commercial Requirements Document;
- Appendix E – Contract (optional if all Proponents have existing agreements); and
- Appendix F – Other Documents (optional).

NOTE: Complete and append all relevant documents ***prior*** to issuing the RFP.

TIP: If you are unsure what information should be entered/selected, contact the Law Department.

INSTRUCTIONS TO PROPONENTS

On the *Cover Page*, complete the following information:

1. **Company** (Enbridge Entity) issuing the RFP

   NOTE: If the goods/services are used by two or more different entities, e.g. Enbridge Pipelines Inc. and Enbridge Pipelines (Athabasca) Inc., enter the following:

   (a) **Canada** - input Company as **Enbridge Employee Services Canada Inc.**

   (b) **U.S.** - select from below:

      i. **Creating a U.S.-wide master agreement**: Input Company as **Enbridge (U.S.) Inc.**

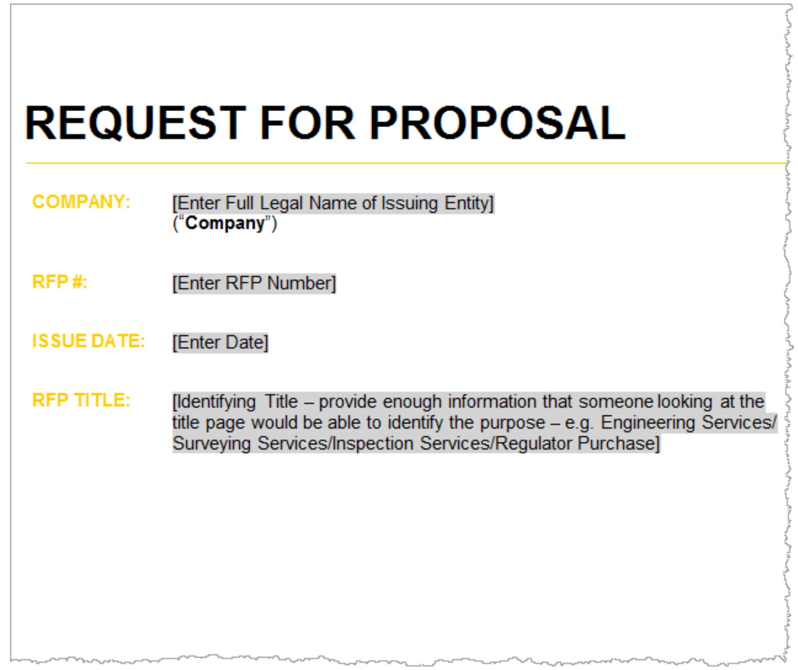
      ii. **NOT creating a U.S.-wide master agreement** List all of the entities that are procuring the goods/services

   TIP: If you are unsure which entity is issuing the RFP, contact the Law Department.

2. **RFP #**: Ensure the RFP number is on both the cover page and the footers for all RFP documents.

3. **Issue Date**: The date the RFP is issued.

4. **RFP Title**: Provide sufficient information to allow a reader of the cover page to readily identify the nature of the goods or services being requested.



REQUEST FOR PROPOSAL

COMPANY:	[Enter Full Legal Name of Issuing Entity] ("**Company**")
RFP #:	[Enter RFP Number]
ISSUE DATE:	[Enter Date]
RFP TITLE:	[Identifying Title – provide enough information that someone looking at the title page would be able to identify the purpose – e.g. Engineering Services/ Surveying Services/Inspection Services/Regulator Purchase]

RFP DATA SHEET

1. Section 1 - Description of RFP Subject

(a) **Option 1**: Scope is ***not*** defined in the Contract (APPENDIX E)
Provide a detailed description of the goods/services being requested.

NOTE: If applicable, include additional documents to describe the scope (maps, specifications, drawings, etc.), and attach/reference these under APPENDIX F.

(b) **Option 2**: Scope is defined in the Contract

Use the Option 2 statement provided here.

Section 1 – Description of RFP Subject	**[Note to Preparer: Choose one of the following options, and delete the other option.]** [Option 1:] Company is requesting Proposals in respect of the following RFP Subject: [describe the goods/ services consistently with the RFP Title on the first page of the RFP. If the RFP Subject is to be provided in certain areas, please reference the applicable map or set of maps "as shown on the maps attached at Appendix F", and include the maps in Appendix F.] [Option 2:] Company is requesting Proposals in respect of the RFP Subject as described in the Contract.

2. Section 1 - Confirmation of Receipt

There are two potential forms of confirmation:

(a) **Option 1**: Require Proponents to submit a signed *Intent to Respond* form (attach form under APPENDIX F).

- Complete the RFP Schedule in the RFP Data Sheet to provide a *Deadline for Intent to Respond Form*.

(b) **Option 2**: Require Proponents to confirm by email that they received the RFP and to provide their contact information.

NOTE: If the Proponent is not required to provide the above confirmation, mark section as **Not Applicable**.

Section 1 – Confirmation of Receipt	**[Note to Preparer: If applicable, choose one of the following options, and delete the other option. If not applicable, mark as "Not Applicable"]** [Option 1: Intent to Respond Form] If Proponent intends to respond, Proponent must indicate its intention to respond by signing and returning a copy of Proponent Intent to Respond Form in the form attached as Appendix F – Intent to Respond Form to this RFP on or before the date noted under RFP Schedule in the RFP Data Sheet. Intent to Respond Form shall be signed and emailed to the RFP Contact at the email address provided in this RFP Data Sheet. [Option 2: Email Confirming Receipt] Upon receipt of this RFP, Proponent shall send an email to the RFP Contact confirming receipt of this RFP and providing Proponent's primary contact name and contact information (email and telephone numbers) to ensure that Proponent receives all subsequent communications pertaining to this RFP. Please note that all Company communications subsequent to the issuance of this RFP (including, without limitation, any Addenda and Query responses) will be circulated to Proponents by email communication to Proponent's primary contact.

3. Section 5 - Company Policies
   (a) Provide the URL to the general Company policies for suppliers.
   (b) Indicate where Proponents may locate Company policies specific to the RFP.
      i. If policies are appended to Contract, reference APPENDIX E.
      ii. If policies are located elsewhere or will be provided separately by the Company, indicate the same.
      iii. If no RFP specific policies exist, delete the second bullet.

Section 5 - Company Policies	• Policies that apply to suppliers generally can be found at: [url] • Policies that specifically pertain to the RFP Subject can be found at: **[Note to Preparer: Determine which option to use – policies may be attached to the Contract in Appendix E, may be a url, may be provided under separate email cover, etc.]**

4. Section 9 - RFP Schedule
   (a) The following dates are mandatory and cannot be deleted:
      i. **Issuance of RFP**
      ii. **Query Deadline**
      iii. **Proposal Submission Deadline**
      iv. **Expiry of Proposal Validity Period** – if applicable, input the expiry date. Otherwise mark as **Not Applicable**.
   (b) The following dates are optional and may or may not be deleted as applicable:
      i. **Deadline for Intent to Respond Form**
      ii. **Confirmation Deadline for [Pre-Proposal Meeting/Site Visit] Attendance** – include if Pre-Proposal Meetings or Site Visits are scheduled; select relevant wording for either a Pre-Proposal Meeting or a Site Visit
      iii. **Proposal Review and Clarification Meetings** – include only if you would like to disclose this information to Proponents

Section 9 – RFP Schedule

[Note to Preparer: Add and delete dates as applicable. To avoid confusion please delete the entire row if one of the events below is not applicable.]

Event	Date and Time
Issuance of RFP:	[Date]
Deadline for Intent to Respond Form	[Date] at * [a.m./p.m.] [MT/CT/ET]
Confirmation Deadline for [Pre-Proposal Meeting/Site Visit]	[Date] at * [a.m./p.m.] [MT/CT/ET]

5. Section 10(a) – RFP Contact

Input the **name**, **title** and **email** of the Company contact person for this RFP.

This person will receive all communications relating to the RFP. This person must be a member of the SCM Department.

Section·10(a)·–·RFP·Contact¤	Name:·[RFP·Contact·Name]·¶ Title:··[RFP·Contact·Title]¶ RFP·Contact·Email:··[RFP·Contact·Email]¤

6. Section 10(a) – Communications

Select the appropriate option based on how the RFP is being issued; delete all other options.

Section 10(a) – Communications	**[Note Preparer: Delete options that are not applicable]** **[MERX]** All communications related to this RFP which do not contain any attachments shall be made in the Q&A section of the RFP Posting. All communications related to this RFP which contain attachments shall be emailed to the RFP Contact. All Queries related to this RFP must be submitted on or before the Query Deadline (Question Acceptance Deadline) as set out in the RFP Posting. **[EMAIL/HARD COPY/SFTP]** All communications related to this RFP shall be emailed to the RFP Contact. **[ARIBA]** Each Proponent will receive an email invitation (from Ariba) containing the URL to the Company's Ariba portal ("**Ariba Portal**"). All communications related to this RFP must be submitted through the Ariba Portal messaging system using the "Compose Message" button found at the lower left hand side in the Ariba Portal. All Queries related to this RFP must be submitted on or before the Query Deadline (Question Acceptance Deadline) as set out in the RFP posting on the Ariba Portal.

7. Section 11(a) – Issuance of Addenda

Select the appropriate option based on how the RFP is being issued; delete all other options.

Addenda are to be issued by the Company when revisions, interpretations and/or any supplemental instructions relating to the RFP are to be provided to all Proponents.

NOTE: The Company has discretion in deciding whether to issue an Addendum, and how to respond to Queries.

It may decide to answer similar questions from different Proponents only once, edit any questions for the purpose of clarity, and/or ignore the Queries altogether (if the Company decides that they are obscure, ambiguous, unclear or not relevant to the RFP).

Section 11(a) - Issuance of Addenda	**[Note to Preparer: Delete options that are not applicable]** **[MERX]** Addenda will be posted under the Document section of the RFP Posting. While the MERX Portal will automatically generate email notifications to Proponent each time an Addendum is posted, it is Proponent's responsibility to ensure that it has reviewed all Addenda posted in the RFP Posting. **[EMAIL/HARD COPY]** Any Addendum issued by Company will be emailed by the RFP Contact to all Proponents. It is Proponent's responsibility to ensure that it has reviewed all Addenda sent by the RFP Contact.

8. Section 23(b)(ii) – Proposal Submission

Select the appropriate option based on how the RFP is being issued; delete all other options.

(a) Email: Complete the information regarding RFP number and Title; establish a group email account to receive Proposals.

(b) **Hard copy**: Indicate whether the Proposal must be sealed, and complete the relevant information in grey.

Section 23(b)(ii) – Proposal Submission	**[Note to Preparer: Delete options that are not applicable]** **[MERX]** Proposal must be submitted electronically through the MERX portal only at http://www.enbridge.merx.com ("**MERX Portal**"). No other forms of submission will be accepted or considered. Proposals must be received no later than the Proposal Submission Deadline set out as the closing date and time for the RFP on the MERX Portal.

9. Section 27(b) – Proposal Withdrawal

Select the appropriate option based on how the RFP is being issued; delete all other options.

Section 27(b) – Proposal Withdrawal	**[Note to Preparer: Delete options that are not applicable]** **[MERX]** Proponent may withdraw its Proposal directly through the RFP Posting up to the Proposal Submission Deadline. Company does not have access to the Proposals until after the Proposal Submission Deadline. As such, Company will only be able to view those Proposals that were submitted (and have not been withdrawn) by Proponents as of the Proposal Submission Deadline. All Proposals viewable by Company shall be deemed to be

10. Section 31(c) – Evaluation and Selection

Sample evaluation and selection language is included in the ACT. Revise the language to reflect the specific requirements for the RFP.

Section 31(c) – Evaluation and Selection	Proposals will be evaluated based upon criteria determined by Company, at its sole and absolute discretion. Such criteria (in no particular order) include, but are not limited to: • the information requested in the Technical Requirements Document; • the information requested in the Commercial Requirements Document; and • the nature and number of contractual, commercial and technical exceptions. The evaluation scoring and weighting given by Company to the evaluation criteria will be at the discretion of Company.

APPENDIX A – PROPOSAL FORMAT AND CONTENTS

Select the appropriate option based on how the RFP is being issued; delete other options.

> **APPENDIX A – PROPOSAL FORMAT AND CONTENTS**
>
> Proposals are to follow the outline described below and must address all requested information. Any additional information that Proponent wishes to include that is not specially requested should be included under Part 2 to the Proposal. Proponents are encouraged to keep their Proposal brief and to the point, but sufficiently detailed to allow evaluation of the approach to the RFP Subject.
>
> **Proponent is to provide each of the Parts as a separate document or package of documents. No pricing is to appear in the Technical Response.**
>
> **[Note to Preparer: Select applicable option and delete the other options]**

APPENDIX B – PROPOSAL SUBMISSION ACKNOWLEDGMENT FORM

Issue the RFP using the template for the *Proposal Submission Acknowledgment Form* set out in APPENDIX B to the RFP.

There is no need to complete any information on this template.

> **APPENDIX B**
> **PROPOSAL SUBMISSION ACKNOWLEDGMENT**
>
> **RFP #:** ____________________
>
> **Proposal Submission**
>
> In consideration of Company's evaluation of our Proposal in accordance with the RFP Documents and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the undersigned Proponent hereby acknowledges and agrees to be bound by and comply with the terms and conditions of the RFP. Proponent hereby represents and warrants to Company that it has carefully and thoroughly examined the RFP Documents in detail, has received all pages of the documents constituting the RFP Documents (including all Addenda issued by Company), and has the resources, skills, capacity and ability to perform the services/provide the goods, as applicable in accordance with the RFP Documents. Unless otherwise defined in this Proposal Submission Acknowledgement, all capitalized terms have the applicable meanings given in the RFP.

APPENDIX C – TECHNICAL REQUIREMENTS DOCUMENT

Follow these guidelines with respect to APPENDIX C:

1. The *Technical Requirements Document* in APPENDIX C is a general template only. Unless specifically stated as mandatory for inclusion, you and the Project team determine whether to add or delete requirements in this document for the purposes of the RFP.
2. This document is for technical (i.e. non-commercial) requirements only. No pricing or pricing-related questions (e.g. volume discounts, incentives, etc.) are to be included in this document.
3. State directly in this document the format(s) a Proponent must use to provide responses.
4. For a Gas Transmission & Midstream (GTM) construction contract, where technical requirements are set out directly in the Contract, refer to the *Technical Requirements Document* for the relevant provisions/attachments to the Contract.

APPENDIX D – COMMERCIAL REQUIREMENTS DOCUMENT

Follow these guidelines with respect to APPENDIX D:

1. The *Commercial Requirements Document* set out in APPENDIX D is a general template only. Unless specifically stated as mandatory for inclusion, you and the Project team determine whether to add or delete requirements in this document for the purposes of the RFP.
2. This document is for commercial requirements only (questions relating to pricing). No technical questions are to be included in this document.
3. State directly in this document the format(s) a Proponent must use to provide responses.
4. For a Gas Transmission & Midstream (GTM) construction contract, where the commercial requirements are set out directly in the Contract, refer to the *Commercial Requirements Document* for the relevant provisions/attachments to the Contract.

APPENDIX E – CONTRACT

Select one of the following options with respect to APPENDIX E:

1. If all Proponents have Existing Agreements, mark APPENDIX E as **Intentionally Deleted**.
2. If not all Proponents have Existing Agreements, select the appropriate Contract to append based on the parameters of use associated with that Contract.

TIP: If you are unsure which Contract should be appended, contact the Law Department.

APPENDIX F – OTHER DOCUMENTS (OPTIONAL)

Follow these guidelines with respect to APPENDIX F:

1. Append other documents applicable to the RFP under APPENDIX F.
2. Include additional information pertaining to the RFP Subject under APPENDIX F (such as specifications, maps, drawings, more descriptive text, etc. not already included in the Contract).
3. Append the *Intent to Respond Form* template, if it is required from the Proponents.

NOTE: If there are no documents to append, do not include APPENDIX F with the RFP documents.

APPENDIX 2 – GUIDANCE FOR USING THE RFQ ACT

STRUCTURE OF RFQ

Each RFQ prepared from the ACT is comprised of the following documents:

- Instructions to Respondents;
- RFQ Data Sheet;
- Appendix A – Quotation Format and Submission;
- Appendix B – Quotation Submission Acknowledgment Form;
- Appendix C – Commercial Requirements Document;
- Appendix D – Contract (optional if all Respondents have existing agreements);
- Appendix E – Other Documents (optional).

NOTE: Complete and append all relevant documents ***prior*** to issuing the RFQ.

TIP: If you are unsure what information should be entered/selected, contact the Law Department.

INSTRUCTIONS TO RESPONDENTS

On the *Cover Page*, complete the following information:

1. **Company** (Enbridge Entity) issuing the RFQ.

   NOTE: If the goods/services are used by two or more different entities, e.g. Enbridge Pipelines Inc. and Enbridge Pipelines (Athabasca) Inc., enter the following:

   (c) **Canada** - input Company as **Enbridge Employee Services Canada Inc.**

   (d) **U.S.** - select from below:

   iii. **Creating a U.S.-wide master agreement**: Input Company as **Enbridge (U.S.) Inc.**

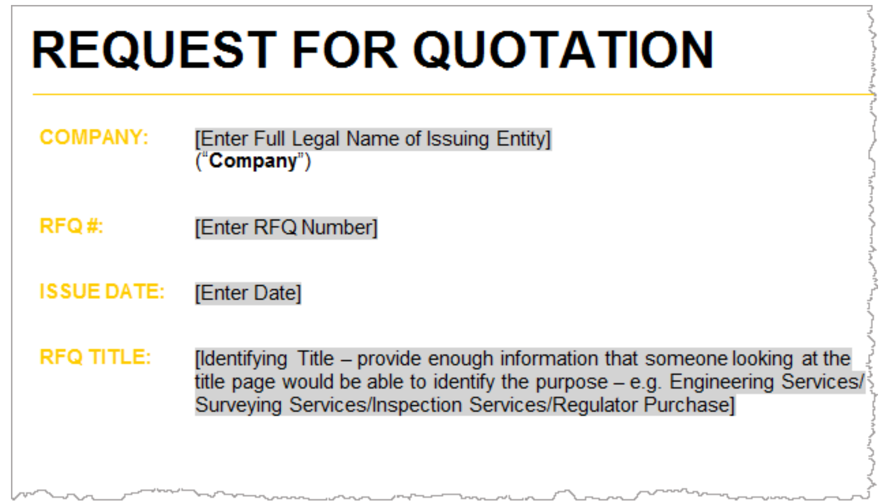
   iv. **NOT creating a U.S.-wide master agreement** List all of the entities that are procuring the goods/services

   TIP: If you are unsure which entity is issuing the RFP, contact the Law Department.

2. **RFQ #**: Ensure the RFQ number is on both the cover page and the footers for all RFQ documents

3. **Issue Date**: The date the RFQ is issued.

4. **RFQ Title**: Provide sufficient information to allow a reader of the cover page to readily identify the nature of the goods or services being requested.



REQUEST FOR QUOTATION

COMPANY: [Enter Full Legal Name of Issuing Entity] ("**Company**")

RFQ #: [Enter RFQ Number]

ISSUE DATE: [Enter Date]

RFQ TITLE: [Identifying Title – provide enough information that someone looking at the title page would be able to identify the purpose – e.g. Engineering Services/ Surveying Services/Inspection Services/Regulator Purchase]

RFQ DATA SHEET

5. Section 1 - Description of RFQ Subject

   (a) **Option 1**: Scope is ***not*** defined in the Contract (APPENDIX D). Provide a detailed description of the goods/services being requested.

   NOTE: If applicable, include additional documents to describe the scope (maps, drawings specifications, etc.), and attach/ reference these under APPENDIX E.

   (b) **Option 2:** Scope is defined in the Contract

   Use the Option 2 statement provided here.

Section 1 – Description of RFQ Subject	**[Note to Preparer: Choose one of the following options, and delete the other option.]** [Option 1:] Company is requesting Quotations in respect of the following RFQ Subject: [describe the goods/ services consistently with the RFQ Title on the first page of the RFQ. If the RFQ Subject is to be provided in certain areas, please reference the applicable map or set of maps "as shown on the maps attached at Appendix E", and include the maps in Appendix E.] [Option 2:] Company is requesting Quotations in respect of the RFQ Subject as described in the Contract.

6. Section 1 - Confirmation of Receipt

   There are two potential form of confirmation:

   (a) **Option 1**: Require Respondents to submit a signed *Intent to Respond* form (attach form under APPENDIX E).

   - Complete the RFQ Schedule in the RFQ Data Sheet to provide a *Deadline for Intent to Respond Form.*

   (b) **Option 2**: Require Respondents to confirm by email that they received the RFQ and to provide their contact information.

   NOTE: If the Respondent is not required to provide the above confirmation, mark section as **Not Applicable**.

Section 1 – Confirmation of Receipt	**[Note to Preparer: If applicable, choose one of the following options, and delete the other option. If not applicable, mark as "Not Applicable"]** [Option 1: Intent to Respond Form] If Respondent intends to respond, Respondent must indicate its intention to respond by signing and returning a copy of Respondent Intent to Respond Form in the form attached as Appendix E – Intent to Respond Form to this RFQ on or before the date noted under RFQ Schedule in the RFQ Data Sheet. Intent to Respond Form shall be signed and emailed to the RFQ Contact at the email address provided in this RFQ Data Sheet. [Option 2: Email Confirming Receipt] Upon receipt of this RFQ, Respondent shall send an email to the RFQ Contact confirming receipt of this RFQ and providing Respondent's primary contact name and contact information (email and telephone numbers) to ensure that Respondent receives all subsequent communications pertaining to this RFQ. Please note that all Company communications subsequent to the issuance of this RFQ (including, without limitation, any Addenda and Query responses) will be circulated to Respondents by email communication to Respondent's primary contact.

7. Section 4 - Company Policies

   (a) Provide the URL to the general Company policies for suppliers.

   (b) Indicate where Respondents may locate Company policies specific to the RFQ.

      i. If policies are appended to Contract, reference APPENDIX D.

      ii. If policies are located elsewhere or will be provided separately by the Company, indicate the same.

      iii. If no RFQ specific policies exist, delete the second bullet.

Section 4 - Company Policies	• Policies that apply to suppliers generally can be found at: [url] • Policies that specifically pertain to the RFQ Subject can be found at: **[Note to Preparer: Determine which option to use – policies may be attached to the Contract in Appendix D, may be a url, may be provided under separate email cover, etc.]**

8. Section 8 - RFQ Schedule

   (a) The following dates are <u>mandatory</u> and cannot be deleted:

      i. **Issuance of RFQ**

      ii. **Query Deadline**

      iii. **Quotation Submission Deadline**

      iv. **Expiry of Quotation Validity Period** – if applicable, input the expiry date. Otherwise mark as **Not Applicable**.

   (b) The following dates are <u>optional</u> and may or may not be deleted as applicable:

      i. **Deadline for Intent to Respond Form**

      ii. **Confirmation Deadline for [Pre-Quotation Meeting/Site Visit] Attendance** - include if Pre-Quotation Meetings or Site Visits are scheduled; select relevant wording for either a Pre-Quotation Meeting or a Site Visit

      iii. **Quotation Review and Clarification Meetings** - include only if you would like to disclose this information to the Respondents

Section 8 – RFQ Schedule

[Note to Preparer: Add and delete dates as applicable. To avoid confusion please delete the entire row if one of the events below is not applicable.]

Event	Date and Time
Issuance of RFQ:	[Date]
Deadline for Intent to Respond Form	[Date] at * [a.m./p.m.] [MT/CT/ET]
Confirmation Deadline for [Pre-Quotation Meeting/Site Visit] Attendance:	[Date] at * [a.m./p.m.] [MT/CT/ET]
Pre-Quotation Meetings:	[NON-MERX (including Ariba)] [Date] at * [a.m./p.m.] [MT/CT/ET] at [Location] [Include any other relevant details] [MERX]

9. Section 9(a) – RFQ Contact

Input the **name**, **title** and **email** of the Company contact person for this RFQ.

This person will receive all communications relating to the RFQ.

This person must be a member of the SCM Department.

Section 9(a) – RFQ Contact	Name: [RFQ Contact Name] Title: [RFQ Contact Title] RFQ Contact Email: [RFQ Contact Email]

10. Section 9(a) – Communications

Select the appropriate option based on how the RFQ is being issued; delete all other options.

Section 9(a) – Communications	**[Note to Preparer: Delete options that are not applicable]** **[MERX]** All communications related to this RFQ which do not contain any attachments shall be made in the Q&A section of the RFQ Posting. All communications related to this RFQ which contain attachments shall be emailed to the RFQ Contact. All Queries related to this RFQ must be submitted on or before the Query Deadline (Question Acceptance Deadline) as set out in the RFQ Posting. **[EMAIL/HARD COPY/SFTP]** All communications related to this RFQ shall be emailed to the RFQ Contact. **[ARIBA]** Each Respondent will receive an email invitation (from Ariba) containing the URL to the Company's Ariba portal ("**Ariba Portal**"). All communications related to this RFQ must be submitted through the Ariba Portal messaging system using the "Compose Message" button found at the lower left hand side in the Ariba Portal. All Queries related to this RFQ must be submitted on or before the Query Deadline (Question Acceptance Deadline) as set out in the RFQ posting on the Ariba Portal.

11. Section 10(a) – Issuance of Addenda

Select the appropriate option based on how the RFQ is being issued; delete all other options.

Addenda are to be issued by the Company when revisions, interpretations and/or any supplemental instructions relating to the RFQ are to be provided to all Respondents.

NOTE: The Company has discretion in deciding whether to issue an Addendum, and how to respond to Queries.

It may decide to answer similar questions from different Respondents only once, edit any questions for the purpose of clarity, and/or ignore the Queries altogether (if the Company decides that they are obscure, ambiguous, unclear or not relevant to the RFQ).

Section 10(a) - Issuance of Addenda	**[Note to Preparer: Delete options that are not applicable]** **[MERX]** Addenda will be posted under the Document section of the RFQ Posting. While the MERX Portal will automatically generate email notifications to Respondent each time an Addendum is posted, it is Respondent's responsibility to ensure that it has reviewed all Addenda posted in the RFQ Posting. **[Email/Hard Copy]** Any Addendum issued by Company will be emailed by the RFQ Contact to all Respondents. It is Respondent's responsibility to ensure that it has reviewed all Addenda sent by the RFQ Contact. **[SFTP]** Any Addendum issued by Company will be posted to a secure file transfer protocol site

12. Section 22(a)(iii) – Quotation Submission

Select the appropriate option based on how the RFQ is being issued; delete all other options.

(a) **Email**: Complete the information regarding the RFQ number and Title; establish a group email account to receive Quotations

(b) **Hard copy**: Indicate whether the Quotation must be sealed, and complete the relevant information in grey.

Section 22(a)(iii) – Quotation Submission	**[Note to Preparer: Delete options that are not applicable]** **[MERX]** Quotation must be submitted electronically through the MERX portal only at http://www.enbridge.merx.com ("**MERX Portal**"). No other forms of submission will be accepted or considered. Quotations must be received no later than the Quotation Submission Deadline set out as the closing date and time for the RFQ on the MERX Portal. Notwithstanding the foregoing, in the extraordinary circumstances that the MERX Portal is not accessible by Respondents due to MERX's server issues, and such issues are not resolved within two (2) hours from the Quotation Submission Deadline, Company, upon written notice to all Respondents, shall extend the Quotation Submission Deadline to such date and time that it, in its sole discretion, deems appropriate to allow all Respondents to submit their Quotations through the MERX Portal. Company reserves the right, in its sole discretion, to accept hard copies of the Quotations in the event that the MERX server

13. Section 26(b) – Quotation Withdrawal

Select the appropriate option based on how the RFQ is being issued; delete other options.

Section 26(b) - Quotation Withdrawal	**[Note to Preparer: Delete options that are not applicable]** **[MERX]** Respondents may withdraw its Quotation directly through the RFQ Posting up to the Quotation Submission Deadline. Company does not have access to the Quotations until after the Quotation Submission Deadline. As such, Company will only be able to view those Quotations that were submitted (and have not been withdrawn) by Respondents as of the Quotation Submission Deadline. All Quotations viewable by Company shall be deemed to be submitted Quotations. **[EMAIL/HARD COPY/SFTP]** Respondent may withdraw its Quotation by email before the Quotation Submission

APPENDIX A – QUOTATION FORMAT AND CONTENTS

Select the appropriate option based on how the RFQ is being issued; delete other options.

APPENDIX A – QUOTATION FORMAT AND CONTENTS

Quotations are to follow the outline described below and must address all requested information. Any additional information that Respondent wishes to include that is not specially requested should be included under Part 2 to the Quotation. Respondents are encouraged to keep their Quotation brief and to the point, but sufficiently detailed to allow evaluation of the approach to the RFQ Subject.

Respondent is to provide each of the Parts as a separate document or package of documents.

APPENDIX B – QUOTATION SUBMISSION ACKNOWLEDGMENT FORM

Issue the RFQ using the template for the *Quotation Submission Acknowledgment Form* set out in APPENDIX B to the RFQ.

There is no need to complete any information on this template.

APPENDIX B
QUOTATION SUBMISSION ACKNOWLEDGMENT

RFQ #: ____________________

Quotation Submission

In consideration of Company's evaluation of our Quotation in accordance with the RFQ Documents and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the undersigned Respondent hereby acknowledges and agrees to be bound by and comply with the terms and conditions of the RFQ. Respondent hereby represents and warrants to Company that it has carefully and thoroughly examined the RFQ Document in

---

APPENDIX C – COMMERCIAL REQUIREMENTS DOCUMENT

Follow these guidelines with respect to APPENDIX C:

1. The *Commercial Requirements Document* set out in APPENDIX C is a general template only. Unless specifically stated as mandatory for inclusion, you and the Project team determine whether to add or delete requirements in this document for the purposes of the RFQ.
2. This document is for commercial requirements only (questions relating to pricing). No technical questions are to be included in this document.
3. State directly in this document the format(s) a Respondent must use to provide responses.
4. For a Gas Transmission & Midstream (GTM) construction contract, where the commercial requirements are set out directly in the Contract, refer to the *Commercial Requirements Document* for the relevant provisions/attachments to the Contract.

APPENDIX D – CONTRACT

Select one of the following options with respect to APPENDIX D:

1. If all Respondents have Existing Agreements, mark APPENDIX D as **Intentionally Deleted**.
2. If not all Respondents have Existing Agreements, select the appropriate Contract to append based on the parameters of use associated with that Contract.

TIP: If you are unsure which Contract should be appended, contact the Law Department.

APPENDIX E – OTHER DOCUMENTS (OPTIONAL)

Follow these guidelines with respect to APPENDIX E:

1. Append other documents applicable to this RFQ under APPENDIX E.
2. Include additional information pertaining to the RFQ Subject under APPENDIX E (such as specifications, maps, drawings, more descriptive text, etc. not already included in the Contract).
3. Append the *Intent to Respond Form* template, if it is required from the Respondents.

NOTE: If there are no documents to append, do not include APPENDIX E with the RFQ documents.

APPENDIX 3 – GUIDANCE FOR USING THE RFI ACT

STRUCTURE OF RFI

Each RFI prepared from the ACT is comprised of the following documents:

- Instructions to Respondents;
- RFI Data Sheet; and
- Appendix A – Other Documents (optional).

NOTE: Complete and append all relevant documents ***prior*** to issuing the RFI.

TIP: If you are unsure what information should be entered/selected, contact the Law Department.

INSTRUCTIONS TO RESPONDENTS

On the *Cover Page*, complete the following information:

1. **Company** (Enbridge Entity) issuing the RFI.

   NOTE: If the goods/services are used by two or more different entities, e.g. Enbridge Pipelines Inc. and Enbridge Pipelines (Athabasca) Inc., enter the following:

   (e) **Canada** - input Company as **Enbridge Employee Services Canada Inc.**

   (f) **U.S.** - select from below:

   v. **Creating a U.S.-wide master agreement**: Input Company as **Enbridge (U.S.) Inc.**

   vi. **NOT creating a U.S.-wide master agreement** List all of the entities that are procuring the goods/services

   TIP: If you are unsure which entity is issuing the RFP, contact the Law Department.

2. **RFI #**: Ensure the RFI number is on both the cover page and the footers for all RFI documents.

3. **Issue Date**: The date the RFI is issued.

4. **RFI Title**: Provide sufficient information to allow a reader of the cover page to readily identify the nature of the goods or services being requested.

REQUEST FOR INFORMATION

COMPANY: [Enter Full Legal Name of Issuing Entity] ("**Company**")

RFI #: [Enter RFI Reference Number]

ISSUE DATE: [Enter Date]

RFI TITLE: [Identifying Title – provide enough information that someone looking at the title page would be able to identify the purpose – e.g. Engineering Services/ Surveying Services/Inspection Services/Regulator Purchase]

RFI DATA SHEET

5. Section 1 - Description of RFI Subject

Describe the scope of the services / goods the Company is requesting information about from the Respondents.

NOTE: If you intend to attach a separate document, mark **See attached** and ensure you append the document under APPENDIX A.

Section 1 – Description of RFI Subject	[**Note to Preparer**: Provide the scope of the services/goods here. If you intend to attach a separate document, please mark "See attached" and ensure that you append the document under Appendix A]

6. Section 5 - RFI Schedule

Enter the following:

(a) **Issuance of RFI**

(b) **Query Deadline**

(c) **Response Submission Deadline**.

Section 5 – RFI Schedule

Event	Date and Time
Issuance of RFI:	[Date]
Query Deadline:	[NON-MERX (including Ariba)] [Date] at * [a.m./p.m.] [MT/CT/ET]

7. Section 6 – RFI Contact

Input the **name**, **title** and **email** of the Company contact person for this RFI.

This person will receive all communications relating to the RFI.

This person must be a member of the SCM Department.

Section 6 – RFI Contact	Name: [RFI Contact Name] Title: [RFI Contact Title] RFI Contact Email: [RFI Contact Email]

8. Section 6 – Communications

Select the appropriate option based on how the RFI is being issued; delete all other options.

Section 6 – Communications	**[Note Preparer: Delete options that are not applicable]** **[MERX]** All communications related to this RFI which do not contain any attachments shall be made in the Q&A section of the RFI Posting. All communications related to this RFI which contain attachments shall be emailed to the RFI Contact.

9. Section 13 – Response Submission

Select the appropriate option based on how the RFI is being issued; delete all other options.

(a) **Email**: Complete the information regarding the RFI number and Title; establish a group email account to receive Responses.

(b) **Hard copy**: Indicate whether the Response must be sealed, and complete the relevant information in grey.

Section 13 – Response Submission	**[Note to Preparer: Delete options that are not applicable]** **[MERX]** Response must be submitted electronically through the MERX portal only at http://www.enbridge.merx.com ("**MERX Portal**"). No other forms of submission will be accepted or considered. Responses must be received no later than the Response Submission Deadline set out as the closing date and time for the RFI on the MERX Portal. Notwithstanding the foregoing, in the extraordinary circumstances that the MERX Portal is not accessible by Respondents due to MERX's server issues, and such issues are not resolved within two (2) hours from the Response Submission Deadline, Company, upon written notice to all Respondents, shall extend the Response Submission Deadline to such

APPENDIX A – OTHER DOCUMENTS (OPTIONAL)

Attach any additional documents applicable to this RFI (e.g. Questionnaire).

NOTE: If there are no documents to append, do not include APPENDIX A with the RFI documents.

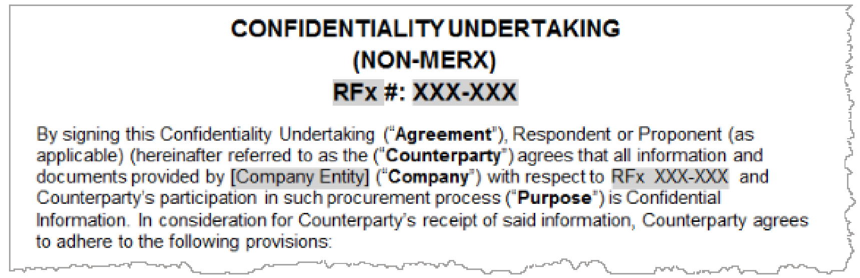
APPENDIX 4: HOW TO COMPLETE A NON-MERX CONFIDENTIALITY UNDERTAKING

DOWNLOAD THE NON-MERX CONFIDENTIALITY UNDERTAKING

1. Download the Non-MERX Confidentiality Undertaking document from the SCM Governance Documents Library.

NOTE: To ensure you are using the latest version, ***always*** download a new copy of the Confidentiality Undertaking.

PREPARE THE NON-MERX CONFIDENTIALITY UNDERTAKING

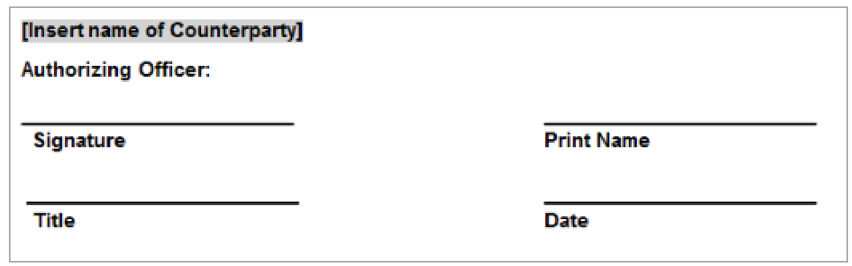

CONFIDENTIALITY UNDERTAKING
(NON-MERX)
RFx #: XXX-XXX

By signing this Confidentiality Undertaking ("**Agreement**"), Respondent or Proponent (as applicable) (hereinafter referred to as the ("**Counterparty**") agrees that all information and documents provided by [Company Entity] ("**Company**") with respect to RFx XXX-XXX and Counterparty's participation in such procurement process ("**Purpose**") is Confidential Information. In consideration for Counterparty's receipt of said information, Counterparty agrees to adhere to the following provisions:

2. In the heading, update references RFx to **RFP, RFQ,** or **RFI,** then insert the applicable **number**.

3. Ensure the **Company** entity matches the Company entity written on the cover page of the Instructions to Proponent/Respondent.

4. Enter the name of the **Counterparty** in the signature block. This must be completed prior to sending to the Respondent/Proponent.


[Insert name of Counterparty]

Authorizing Officer:

Signature	**Print Name**
Title	**Date**

5. Save the completed document as a .PDF file before sending to the Respondent/Proponent. No exceptions to the form are allowed.

NOTE: Ensure a signed copy of the Non-MERX Confidentiality Undertaking is obtained from the Respondent/Proponent before sending the RFx documents.

APPENDIX 5: HOW TO COMPLETE A MERX CONFIDENTIALITY UNDERTAKING

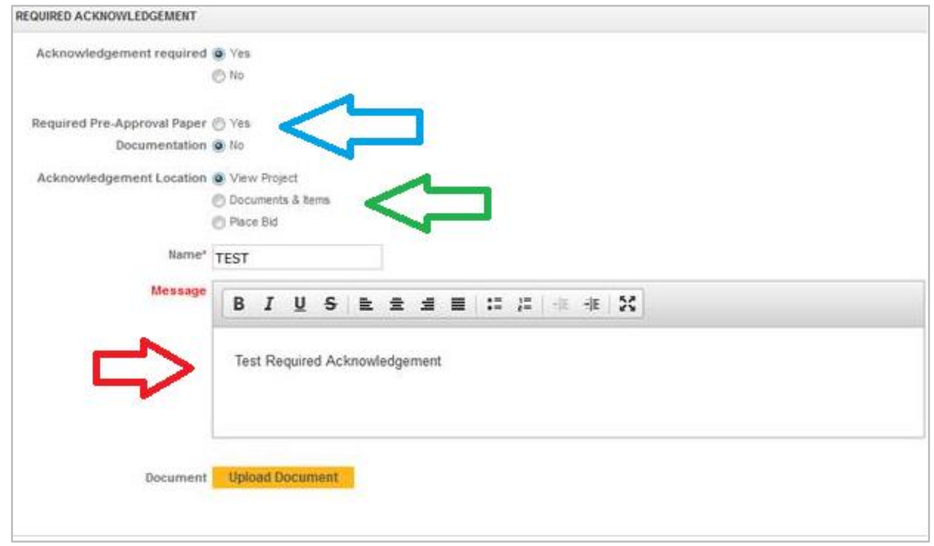
DOWNLOAD THE MERX CONFIDENTIALITY UNDERTAKING

1. Download the MERX Confidentiality Undertaking document from the SCM Governance Documents Library.

NOTE: To ensure you are using the latest version, ***always*** download a new copy of the Confidentiality Undertaking.

PREPARE THE MERX CONFIDENTIALITY UNDERTAKING

2. Access the online form in MERX.



3. In the Required Acknowledgement section, complete the following:

   (a) **Acknowledgement Required**: Select **Yes**.
   This is required by the Proponent prior to gaining access to the RFx documents.

   (b) **Required Pre-Approval Paper Documentation**: Select **No**.
   The Company does not require a paper copy; electronic approval is sufficient.

   (c) **Acknowledgement Location**: Select **View Project**.
   This enforces the Proponent/Respondent to accept before seeing the RFx details.

   (d) **Name**: Enter **Confidentiality Undertaking**.

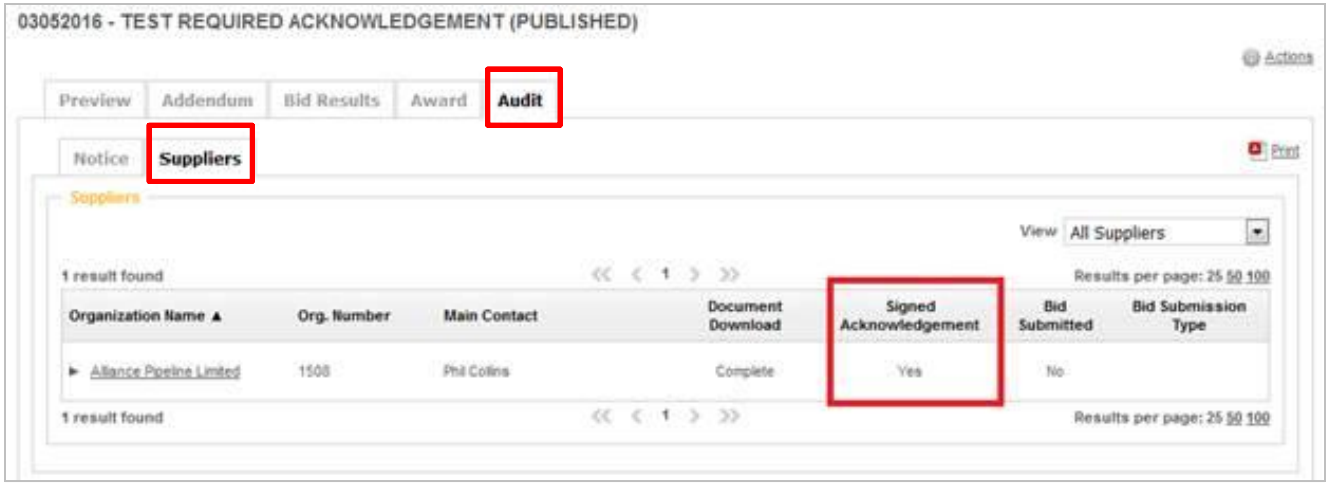
4. In the **Message** section, enter the following statement,

   "*By clicking "Accept", the Proponent/Respondent confirms that:*
   1) it has read the attached Confidentiality Undertaking and
   2) it understands and agrees to be bound by the terms and
   conditions in the Confidentiality Undertaking."

NOTE: If the Proponent/Respondent selects **Decline** to this statement, the Proponent/Respondent will not get access to the RFx documents.

5. Click **Upload Document.**

6. View the *Audit* tab, *Suppliers* section to check to see if the Proponent/Respondent has Accepted or Declined the Terms and Conditions of the Confidentiality Undertaking.



ENBRIDGE

Version #: R2

Version Date:

SINGLE SOURCE JUSTIFICATION (SSJ) ≥ $2MM

Supply Chain Management

INITIATIVE / PROJECT DETAILS	
INITIATIVE / PROJECT NAME	DATE
SINGLE SOURCE JUSTIFICATION RECOMMENDED TO: *(Enter Supplier Full Legal Name)*	
TYPE: ☐ Service ☐ Material	

CONTRACT DETAILS

DESCRIPTION OF SCOPE OF WORK:

CONTRACT TERM	
EFFECTIVE DATE	EXPIRY DATE
CONTRACT DURATION	

CONTRACT TYPE

☐ Frame Agreement (Category Management)
☐ Master Services Agreement
☐ Consulting Services
☐ Facilities Construction
☐ Off-site Fabrication
☐ Other (Identify)___________________________
☐ Work Release (mechanism for work under a Frame Agreement)
☐ Engineering Services Agreement
☐ Consulting Engineering Services Agreement
☐ Pipeline Construction
☐ Work Order/Purchase Order

FORM OF AGREEMENT (1)

☐ Authorized Contract Template: Enter Name of Authorized Contract Template

☐ Non-Authorized Contract Template

(1) As defined in the Contracts Policy

COMMERCIAL STRUCTURE

☐ **Lump Sum**

☐ **Unit Price**

☐ **Time & Materials**

☐ **Actual Cost Plus Fixed Fee**

☐ **Actual Cost with Target Price**

☐ **Other (Identify): ______________________**

ESTIMATED CONTRACT VALUE AND PROJECT BUDGET

Estimated Original Contract Value (1): ☐ Canadian Dollars

Change Order Allowance: ☐ US Dollars

Total Budget:

Task Code(2): ________________________ **PCN Required(2):** ☐ **Yes, PCN #_______** ☐ **No** ☐ **In Progress**

Project Controls Approval (3): ______________________

FREIGHT INCLUDED IN PRICE (POS ONLY): ☐ **Yes** ☐ **No**

DELIVERY TERMS (POS ONLY):

(1) For Contracts which are not Lump Sum the estimated contract value represents the “not to exceed” value.

(2) Not applicable to Frame Agreements.

(3) This approval is to confirm the availability of funds that will ultimately be committed through the Contract resulting from this Contract Award Recommendation. This approval is not applicable to Frame Agreements.

SUPPLIER PRE-QUALIFICATION

IS THE SUPPLIER PRE-QUALIFIED AS PER THE BUSINESS UNIT PRE-QUALIFICATION PROCESS?

☐ Yes

☐ No If no, was exception approved as per the business unit exception process, or has the pre-qualification form been submitted?

☐ Exception approved and **documentation attached**

☐ Pre-Qualification form has been submitted

FINANCIAL STABILITY REVIEW

Is a Financial Stability Review (FSR) required as per the SCM Sourcing Procedure?

ENBRIDGE

SINGLE SOURCE JUSTIFICATION (SSJ) ≥ $2MM Supply Chain Management	Version #: R2 Version Date:

☐ **Yes** ☐ **No**

If FSR is required, what was the response from Corporate Credit?

☐ **Financially Stable** ☐ **Not Financially Stable**

PERFORMANCE SECURITY

In accordance with the Business Stakeholder Team decision and the Terms and Conditions is a Performance Security required?

☐ **No (Provide reason & attach supporting documentation, if applicable)**

Reason: ____

☐ **Yes (Indicate which type)**

- ☐ **Irrevocable Letter of Credit -value (Identify $CDN or $US)** $__________________
- ☐ **Performance Bond -value (Identify $CDN or $US)** $_________________________
- ☐ **Parent Company Guarantee**
- ☐ **Other (Please specify):** ____

BUSINESS JUSTIFICATION FOR SINGLE SOURCE

☐ **Only one supplier able to meet Business Need**

☐ **Business Need includes matters of confidential or privileged nature**

☐ **Business Need has transportation costs or technical considerations that impose geographic limits on the supply base**

☐ **An open sourcing process could interfere with the Company's ability to maintain security or order to protect human, animal, or plant life or health**

☐ **Other (Provide details below)**

DEMONSTRATION OF JUSTIFICATION:

MARKET ANALYSIS [(1)]

(1) Evidence that the scope of work has benchmark data (i.e. current market pricing data, relevant historical spend analysis) to ensure negotiated pricing will be competitive.

INDIGENOUS ECONOMIC PARTICIPATION

(The Indigenous Economic Participation Section is applicable to sourcing activities for services in geographic areas in which Enbridge is actively engaging with Indigenous communities. If you require clarification, please contact SCM Indigenous Engagement (SCM IE). The capacity within the Indigenous business community is constantly increasing, please check with SCM IE to ensure opportunities for Indigenous businesses to participate in projects and operations are not overlooked. SCM IE can be reach at indigenousbusiness@enbridge.com.)

Indigenous Economic Participation Strategy:

<At minimum, Contractor will follow the Socio-Economic Requirements of Contractors (SERC) and will submit a Socio-Economic Plan (SEP) for review by the SCM Indigenous Engagement Team>

Potential Indigenous Sub-Contract Participation:

Potential Scopes of Work	Indigenous Community(ies)	Indigenous Business(es)	Inclusion Strategy	Estimated Value	Allowable Premium %
			<Competitive/Set-Aside/Sole-Source>		
Total					

Internal Target Indigenous Economic Participation %: ______

Internal Target for Indigenous Labour %: ______

Risk, Mitigations and Communication Strategy:

Community	Risks Associated with the Single Source Selection	Risk Level	Mitigation Including Alternative Contracting Opportunities	Communication Strategy & Execution Sequencing	Owner
	<Risks of single source decision – potential Indigenous business that could have executed work>				

ENBRIDGE

SINGLE SOURCE JUSTIFICATION (SSJ) ≥ $2MM

Supply Chain Management

Version #: R2

Version Date:

SCM INDIGENOUS ENGAGEMENT ENDORSEMENT:

Name, Title

PACS COMMUNITY INDIGENOUS ENGAGEMENT / TRIBAL ENGAGEMENT ENDORSEMENT:

Name, Title

SUSTAINABILITY & SUPPLIER DIVERSITY PARTICIPATION

(The Sustainability and Supplier Diversity Participation Section is applicable to sourcing activities for business needs enterprise wide. Please contact SCM Sustainability to ensure opportunities for sustainable and/or diverse businesses to participate in projects and operations are not overlooked. The SCM Sustainability and Supplier Diversity can be reached at supplierdiversity@enbridge.com.)

Potential Environmental Sustainability Opportunity	☐ **Reduce energy or fuel consumption / energy efficient solution** ☐ **Renewable, recyclable, refurbished solution** ☐ **Reduced use of natural resources / conservation solution** ☐ **Reduced waste solution** ☐ **Reduced emissions solution** ☐ **Reduced consumption solution** ☐ **Other:**

Potential Diverse and Sustainability Contracting Considerations:

[1] Diverse Proponent's Name	Classifications e.g. Women-Owned etc.	Direct or Indirect Supplier	Inclusion Strategy	Certificate Number and Expiration Date (if known)
			<Competitive/Set-Aside/Sole-Source>	

[1] Link for *Diverse Supplier Classifications*

SCM SUSTAINABILITY AND SUPPLIER DIVERSITY ENDORSEMENT:

Name, Title

SUMMARY OF TERMS AND CONDITIONS REVISED & FUNCTIONALLY ENDORSED

(Briefly describe details of the major risks associated with the acquisition and/or ability to deliver the Business Need, how they are going to be managed and where appropriate attach a copy of the Risk Register)

(Briefly describe details of unique commercial terms I.E.: Prepayments, Discount rates, < net 60 days payment, etc.)

SUMMARY OF UNIQUE COMMERCIAL TERMS

LIMITED AUTHORIZATION TO PROCEED (LATP)

☐ **Not Applicable**

In accordance with Section 17 – Limited Authorization to Proceed of the SCM Sourcing Procedure the following requirements are applicable and are to be met.

☐ **Written Business Stakeholder approval attached as per ASL (email, etc.)**

☐ **Written Law approval attached (email, etc.)**

The LATP is a pre-contractual agreement prior to the Contract execution but will form part of the final contract and requires the following information to be included:

RFP/RFQ Documents Applicable:

Not To Exceed Value: $ ☐ Canadian Dollars

☐ US Dollars

Scope of Work:

Mobilization Date:

LATP Validity Period:

Forecast Date of Contract Execution:

ENBRIDGE

SINGLE SOURCE JUSTIFICATION (SSJ) ≥ $2MM

Supply Chain Management

Version #: R2

Version Date:

ENDORSEMENT AND AUTHORIZATION			
SCM ENDORSEMENT (1)			
NAME (PRINT)	**TITLE**	**SIGNATURE**	**DATE**
BUDGET OWNER ASL (AUTHORIZATION) (2)			
NAME (PRINT)	**TITLE**	**SIGNATURE**	**DATE**

(1) Endorsement
SCM Manager responsible for sourcing

(2) Authorization
The individual having the proper authority to the Authorities & Spending Limits to authorize the spend and eventual commitment of funds for the estimated total contract value of the Single Source Justification scope of materials/services.

PLEASE RETURN TO ______________

ENBRIDGE

SINGLE SOURCE JUSTIFICATION (SSJ) < $2MM

Supply Chain Management

Version #: R2

Version Date:

INITIATIVE / PROJECT DETAILS	
INITIATIVE / PROJECT NAME	**DATE**
SINGLE SOURCE JUSTIFICATION RECOMMENDED TO: *(Enter Supplier Full Legal Name)*	
TYPE: ☐ **Service** ☐ **Material**	

CONTRACT DETAILS

DESCRIPTION OF SCOPE OF WORK:

CONTRACT TERM	
EFFECTIVE DATE	**EXPIRY DATE**
CONTRACT DURATION	

CONTRACT VALUE AND PROJECT BUDGET

☐ **Budgeted**

☐ **Unbudgeted**

Estimated Contract Value (1): ☐ Canadian Dollars

Budget: ☐ US Dollars

Delta (2):

(1) The estimated value of the total scope of work recognizing where the scope may be segregated into one or more contracts whose cumulative value will equal the above.

(2) Where estimated Contract value exceeds budget, offsets are to be identified.

SINGLE SOURCE JUSTIFICATION (SSJ) < $2MM Supply Chain Management	Version #: R2 Version Date:

FORM OF AGREEMENT (1)

☐ Authorized Contract Template: ______________________Enter Name of Authorized Contract Template______________________

☐ Non-Authorized Contract Template

(1) As defined in the Contracts Policy

BUSINESS JUSTIFICATION FOR SINGLE SOURCE

☐ **Only one supplier able to meet Business Need**

☐ **Business Need includes matters of confidential or privileged nature**

☐ **Business Need has transportation costs or technical considerations that impose geographic limits on the supply base**

☐ **An open sourcing process could interfere with the Company's ability to maintain security or order to protect human, animal, or plant life or health**

☐ **Other (Provide details below)**

DEMONSTRATION OF JUSTIFICATION:

MARKET ANALYSIS (1)

(1) Evidence that the scope of work has benchmark data (i.e. current market pricing data, relevant historical spend analysis) to ensure negotiated pricing will be competitive.

INDIGENOUS ECONOMIC PARTICIPATION

(The Indigenous Economic Participation Section is applicable to sourcing activities for services in geographic areas in which Enbridge is actively engaging with Indigenous communities. If you require clarification, please contact SCM Indigenous Engagement (SCM IE). The capacity within the Indigenous business community is constantly increasing, please check with SCM IE to ensure opportunities for Indigenous businesses to participate in projects and operations are not overlooked. SCM IE can be reached at indigenousbusiness@enbridge.com.)

Indigenous Economic Participation Strategy:

<At minimum, Contractor will follow the Socio-Economic Requirements of Contractors (SERC) and will submit a Socio-Economic Plan (SEP) for review by the SCM Indigenous Engagement Team>

Potential Indigenous Sub-Contract Participation:

Potential Scopes of Work	Indigenous Community(ies)	Indigenous Business(es)	Inclusion Strategy	Estimated Value	Allowable Premium %
			<Competitive/Set-Aside/Sole-Source>		
Total					

Internal Target Indigenous Economic Participation %: ______

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Risk, Mitigations and Communication Strategy:

Community	Risks Associated with the Single Source Selection	Risk Level	Mitigation Including Alternative Contracting Opportunities	Communication Strategy & Execution Sequencing	Owner
	<Risks of single source decision – potential Indigenous business that could have executed work>				

Version #: R2

Version Date:

SINGLE SOURCE JUSTIFICATION (SSJ) < $2MM

Supply Chain Management

SCM INDIGENOUS ENGAGEMENT ENDORSEMENT:

Name, Title

PACS COMMUNITY INDIGENOUS ENGAGEMENT / TRIBAL ENGAGEMENT ENDORSEMENT:

Name, Title

SUSTAINABILITY & SUPPLIER DIVERSITY PARTICIPATION

(The Sustainability and Supplier Diversity Participation Section is applicable to sourcing activities for business needs enterprise wide. Please contact SCM Sustainability to ensure opportunities for sustainable and/or diverse businesses to participate in projects and operations are not overlooked. The SCM Sustainability and Supplier Diversity can be reached at supplierdiversity@enbridge.com.)

Potential Environmental Sustainability Opportunity	☐ **Reduce energy or fuel consumption / energy efficient solution** ☐ **Renewable, recyclable, refurbished solution** ☐ **Reduced use of natural resources / conservation solution** ☐ **Reduced waste solution** ☐ **Reduced emissions solution** ☐ **Reduced consumption solution** ☐ **Other:**

Potential Diverse and Sustainability Contracting Considerations:

[1] Diverse Proponent's Name	Classifications e.g. Women-Owned etc.	Direct or Indirect Supplier	Inclusion Strategy	Certificate Number and Expiration Date (if known)
			<Competitive/Set-Aside/Sole-Source>	

[1] Link for *Diverse Supplier Classifications*

SCM SUSTAINABILITY AND SUPPLIER DIVERSITY ENDORSEMENT:

Name, Title

SUPPLIER PRE-QUALIFICATION

IS THE SUPPLIER PRE-QUALIFIED AS PER THE BUSINESS UNIT PRE-QUALIFICATION PROCESS?

☐ Yes

☐ No If no, was exception approved as per the business unit exception process, or has the pre-qualification form been submitted?

- ☐ Exception approved and **documentation attached**
- ☐ Pre-Qualification form has been submitted

ENBRIDGE

SINGLE SOURCE JUSTIFICATION (SSJ) < $2MM

Supply Chain Management

Version #: R2

Version Date:

ENDORSEMENT AND AUTHORIZATION			
SCM ENDORSEMENT (1)			
NAME (PRINT)	**TITLE**	**SIGNATURE**	**DATE**
BUDGET OWNER ASL (AUTHORIZATION) (2)			
NAME (PRINT)	**TITLE**	**SIGNATURE**	**DATE**

(1) Endorsement
SCM Manager responsible for sourcing

(2) Authorization
The individual having the proper authority to the Authorities & Spending Limits to authorize the spend and eventual commitment of funds for the estimated total contract value of the Single Source Justification scope of materials/services.

PLEASE RETURN TO ________________

DEPRECIATION EXPENSE

DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS

1. The purpose of this evidence is to request OEB approval of Enbridge Gas's depreciation rates and depreciation expense for the 2024 Test Year. This evidence provides details of depreciation and amortization by asset group (storage, transmission, distribution and general) and plant account. The depreciation rates set out in this evidence are derived through a depreciation study completed by Concentric Advisors, ULC. (Concentric) for Enbridge Gas (Enbridge Gas Depreciation Study), which is provided at Attachment 1. Concentric has provided recommendations on depreciation and net salvage methodologies as well as asset useful lives. Enbridge Gas also requests approval for the alignment of 1) asset groups and plant accounts for the EGD and Union rate zones, 2) depreciation methodologies and 3) net salvage approaches for site restoration costs (SRC), all of which are included in the Enbridge Gas Depreciation Study and resulting depreciation rates. Finally, the evidence addresses the consideration of the potential impact of energy transition on the expected useful lives of Enbridge Gas's assets.

2. This evidence also addresses the OEB directive from EGD's 2014 to 2018 IRM Decision[1] to examine the issue of whether a segregated fund for SRC should be established and to undertake additional work regarding the discount rate used in the determination of SRC.

[1] EB-2012-0459, OEB Decision with Reasons, July 17, 2014, pp.56-58.

3. This evidence is organized as follows:
    1. Depreciation Policies Prior to Amalgamation
    2. Depreciation between 2019 to 2023
    3. Proposed Changes at 2024 Rebasing
    4. Energy Transition Considerations
    5. Site Restoration Costs
    6. Depreciation Schedules

1. Depreciation Policies Prior to Amalgamation

4. EGD and Union have depreciated assets in accordance with the depreciation studies filed in EGD's 2013 Cost of Service[2] proceeding (EGD Depreciation Study) and Union's 2013 Cost of Service[3] proceeding (Union Depreciation Study). EGD's depreciation rates were last approved in the 2014 to 2018 Custom IR[4] proceeding, following a change in the SRC approach.

5. Depreciation rates are comprised of two components: the expected service life of the asset and the estimate of net salvage. Depreciation rates in the EGD Depreciation Study were calculated using the straight-line method of depreciation, incorporating the average life group (ALG) procedure applied on the remaining life basis. EGD applied the group concept for all assets. Net salvage was estimated using the Constant Dollar Net Salvage (CDNS) methodology and is included as a component of the depreciation rate.

6. Depreciation rates in the Union Depreciation Study were calculated using straight-line method of depreciation, incorporating the generation arrangement procedure

[2] EB-2011-0354.
[3] EB-2011-0210.
[4] EB-2012-0459, OEB Decision and Order, August 22, 2014.

applied on the remaining life basis. Union applied the group concept for all assets and applied amortization accounting to retire assets for certain general plant and distribution assets. Net salvage was estimated using the Traditional Method and is included as a component of the depreciation rate. The Enbridge Gas Depreciation Study details the differences in depreciation and net salvage methodologies at page 13 and 20 respectively.

2. Depreciation between 2019 to 2023

7. The amalgamation of EGD and Union led to the alignment of various accounting policies, including depreciation procedures and methodologies. A review of existing accounting policies found two differences related to the depreciation of assets at EGD and Union:
    a) Depreciation expense methodology in year of addition and retirement
    b) Depreciation procedure and rates

2.1. Depreciation Expense Methodology in Year of Addition and Retirement

8. EGD historically calculated and recorded depreciation expense beginning the month after the asset went into service and ceased the month following retirement. Union historically recognized depreciation expense based on a half-year approach where, regardless of the month the asset was placed into service, a half-year of depreciation was recognized. Similarly, retirements recognized a half-year of depreciation expense in the year of retirement.

9. Effective January 1, 2019, Enbridge Gas aligned the methodologies and adopted the EGD method of applying depreciation expense beginning the month following an asset being placed into service and ceasing the month following retirement. This

method is preferred as it is more accurate in matching the in-service & retirement date of an asset and the resulting depreciation expense impact.

10. The impact of implementing the EGD method consistently across rate zones for Enbridge Gas is provided in Table 1. The 2019 to 2023 impacts that resulted from the alignment in methodology were captured in the Accounting Policy Change Deferral Account (APCDA) balance, which is being requested for disposition, as provided at Exhibit 9, Tab 2, Schedule 1.

Table 1
APCDA Depreciation Expense

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)	(d)	(e)	(f)
1	Depreciation Expense - Aligned Method	290.3	308.8	317.4	330.4	344.4	433.3
2	Depreciation Expense – Half-Year Method	295.0	312.3	322.3	334.6	353.7	437.8
3	Change in Depreciation Expense	(4.7)	(3.5)	(4.9)	(4.2)	(9.4)	(4.5)

Note:
(1) Negatives represent decreases in depreciation.

2.2. Depreciation Procedures and Rates

11. The determination of the depreciation rates employed by EGD and Union included some differences which contributed to different depreciation rates being applied to similar assets. Please see Table 2 for a summary of the differences. Enbridge Gas is required to apply OEB-approved depreciation methodologies and rates to assets in order to calculate depreciation expense. After receiving OEB approval to amalgamate EGD and Union, Enbridge Gas continued to apply the rates approved in the EGD Depreciation Study and the Union Depreciation Study throughout the

deferred rebasing term and these have been applied to the respective asset bases of each of the EGD and Union rate zones.

Table 2
Summary of Key Depreciation Parameters

Topic	Approved EGD Methodology	Approved Union Methodology	Proposed Enbridge Gas Methodology
Group Depreciation Procedure (Straight Line Method)	ALG Procedure	Generation Arrangement Procedure	ELG Procedure
Amortization Accounting	n/a	Amortization Accounting for certain assets	Amortization Accounting for certain assets
Net Salvage Methodology	CDNS	Traditional Approach	CDNS

3. Proposed Changes at 2024 Rebasing

12. Enbridge Gas engaged Concentric to conduct a depreciation study based on a review of assets in service through December 31, 2021. As part of the Enbridge Gas Depreciation Study, Concentric reviewed existing depreciation parameters, methodologies, and procedures and made recommendations to be applied to the combined asset groups of Enbridge Gas. Table 2 summarizes the topics and recommendations.

3.1. Depreciation Methodology

13. As noted in paragraphs 5 and 6, EGD and Union previously followed the ALG and Generation Arrangement procedures, respectively. The recommended depreciation methodology for Enbridge Gas is the equal life group (ELG) procedure as provided at Attachment 1, pages 16-17. The ELG procedure is viewed as the best option for Enbridge Gas as it offers the following advantages over other methodologies:

a) Enhances the generational equity for customers;
b) Provides superior matching of the depreciation expense to the consumption of assets providing service to customers; and
c) More accurately reflects the actual useful life of the assets used.

14. Concentric has also recommended moving Enbridge Gas to amortization accounting for certain general plant and distribution assets. Amortization accounting is appropriate for plant accounts where there are numerous units of property that are not practical to track and retire on an individual basis (such as tools, regulators, etc.). This is a change for both the EGD and Union rate zones as EGD rate zone did not previously apply amortization accounting and Union rate zone is currently applying the method to only a few assets classes. A full list of the asset categories moving to amortization accounting is provided at Attachment 1, page 37.

15. Currently, EGD rate zone is not applying amortization accounting. These assets are retired once they are no longer in use, as opposed to retiring based on expected useful lives. Under this approach, certain asset classes could end up accumulating more (or less) depreciation if they are retired later (or earlier) than their expected useful lives. This effect is typically mitigated by regular depreciation studies to continuously rebalance the accumulated depreciation by adjusting depreciation rates.

16. Due to the deferral of rebasing, the EGD rate zone has accumulated significant balances in its computer hardware and software accumulated depreciation accounts because the depreciation rates have not been reviewed since the last OEB-approved depreciation study filed in EGD's 2013 Cost of Service[5]. As a result,

[5] EB-2011-0354.

Concentric has recommended establishing new plant accounts for computer hardware and software to depreciate assets going into service after January 1, 2024. The pre-existing accounts will remain, however no new assets will be added after December 31, 2023. The variance between the calculated accrued depreciation and the book accumulated depreciation as of December 31, 2021, will be amortized over the composite remaining life of the assets. Once the last asset is retired for the pools in these pre-existing accounts, depreciation expense will cease on these accounts.

3.2. Net Salvage Methodology

17. In accordance with the OEB Uniform System of Accounts (USoA), EGD and Union have historically recovered the future cost of abandoning assets through the net salvage component of depreciation rates. EGD rate zone currently uses the CDNS method while Union rate zone uses the Traditional Method. The Enbridge Gas Depreciation Study details the differences in methodologies for net salvage on pages 20-23. Concentric recommends the use of the CDNS method for Enbridge Gas as it aligns with the current method approved by the OEB for the EGD rate zone, is more generationally equitable for customers by passing on the benefit of any return on capital and adjusts for inflation in the future requirement of net salvage.

18. In its decision for EGD's 2014 to 2018 IRM, the OEB directed that the discount rate used to calculate net salvage under CDNS should be examined in more detail at the next rebasing proceeding.[6] Concentric recommended the use of a credit adjusted risk-free (CARF) rate as an appropriate discount rate on the basis that the CARF is consistent with discount rates mandated by accounting standards for asset retirement obligations for financial statement disclosures and estimating the discount

[6] EB-2012-0459, OEB Decision with Reasons, July 17, 2014, pp.56-58.

rate in securitization calculations. The CARF is also aligned with other pipelines in similar applications to the Canadian Energy Regulator (CER). Enbridge Gas's CARF was 3.78% at the time the substantive work on the depreciation study was performed, which approximates the discount rate of 3.75% used by Concentric.

3.3. Alignment of Asset Accounts

19. The historical depreciation rates used by Enbridge Gas are comprised of assets based on three rate zones: EGD, Union North and Union South. Each rate zone categorized assets based on the OEB USoA, however there are differences in the classification of assets within these accounts. Alignment is required for Concentric to propose a single depreciation rate for each asset account in the Enbridge Gas Depreciation Study.

20. Enbridge Gas initiated a review of the EGD and Union rate zone asset classes and prioritized alignment based on known differences in asset classifications[7]. Areas investigated include:

    a) Parkway to Albion assets – identified as requiring alignment as the assets are classified as transmission for cost allocation purposes and were previously classified as distribution assets;
    b) Distribution and transmission mains assets – identified as requiring alignment as the Union North and South rate zones were not previously aligned in the classification and the EGD rate zone did not classify any pipeline assets as transmission;

[7] Given the timing of completion of the Enbridge Gas Depreciation Study and the completion of this detailed review of each of EGD and Union rate zones asset classes, there are a limited number of asset classes that have not been reflected in the Depreciation Study. This additional asset class alignment is not material to the results of the study and forecasted depreciation for the 2024 Test Year.

c) Classification of regulators – identified as requiring alignment as the Union rate zones present these assets in separate asset accounts whereas the EGD rate zone combines them with the services account. Separating the assets will align the useful life and retirement practices for regulators;
d) General plant structures and improvements – identified as requiring alignment as some facilities were supporting general utility operations and were not solely used for distribution operations; and
e) Natural gas vehicle (NGV) compressor stations – identified as requiring alignment as the EGD and Union have similar assets but are classifying them in different accounts.

21. Enbridge Gas reflected the alignment impacts listed on the areas above in the December 31, 2021, plant account balances that underpinned the Enbridge Gas Depreciation Study. An explanation of the impacts is provided in the sections that follow below.

Classification of Distribution and Transmission Assets

22. The review of asset classes highlighted a difference in the classification of distribution and transmission assets for depreciation purposes. Historically, EGD classified all pipelines as distribution as they have not met the OEB definition for transmission pipelines. The OEB Filing Guidelines on the Economic Tests for Transmission Pipeline Applications provides the following guidance:

> …transmission pipelines are defined as any planned or proposed pipeline project that would provide transportation services to move natural gas on behalf of other shippers within Ontario[8]

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[8] EB-2012-0092, Appendix A, p.1.

23. Union used both distribution and transmission classifications for pipelines, however the definitions for Union North and Union South were not aligned. Union South defined the classification of pipelines based on engineering standards for operating pressure, diameter of the pipe and the type of customers served directly off the pipeline. Union North maintained the historical Centra Gas[9] classifications and, similar to EGD, classified all pipelines as distribution.

24. Other related asset categories that require a similar distinction/classification between distribution and transmission pipeline include transmission plant land (460), transmission plant land rights (461), transmission plant measuring and regulating equipment (467), distribution plant land (470), distribution plant land rights (471), distribution plant services (473) and distribution plant measuring and regulating equipment (477).

25. Enbridge Gas is proposing to align the EGD and Union North rate zones with the Union South rate zone approach for determining whether pipelines are classified as distribution or transmission for depreciation purposes. The Union South approach is consistent with the Enbridge Gas engineering standards which were defined for the amalgamated utility. Enbridge Gas engineering standards are based on guidance from the Canadian Standards Association (CSA) definition in CSA Z662 and the amended definition in the Technical Standards & Safety Authority (TSSA) Code Adoption Document[10]. The resultant re-classification has been incorporated into the Concentric depreciation study and is reflected in the proposed depreciation rates for the accounts listed below. The pipeline and related facility amounts that have been reclassified from distribution to transmission for the Parkway to Albion assets are

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[9] Union Gas and Centra Gas amalgamated in 1998.
[10] Oil and Gas Pipeline Systems Code Adoption Document Amendment, December 8, 2020. https://www.tssa.org/en/fuels/resources/Pipelines-CAD-Dec-8-2020.pdf.

shown in Table 3 and the pipeline amounts reclassified for other distribution pipelines is shown in Table 4.

Table 3
Parkway to Albion - Summary of Adjustments

Asset Account	$ Change in Account as of Dec 31, 2021 Increase/(decrease)	Accumulated Depreciation as of Dec 31, 2021
460 – Transmission Plant Land	$42,978	n/a
461 – Transmission Plant Land Rights	$19,861,050	$1,335,266
465 – Transmission Plant Mains	$368,401,499	$53,209,524
467 – Transmission Plant Measuring and Regulating Equipment	$3,464,000	$404,603
470 – Distribution Plant Land	($42,978)	n/a
471 – Distribution Plant Land Rights	($19,861,050)	($1,335,266)
475 - Distribution Plant Mains	($368,401,499)	($53,209,524)
477 - Distribution Plant Measuring and Regulating Equipment	($3,464,000)	($404,603)

Table 4
Distribution to Transmission Mains – Summary of Adjustments

Asset Account	$ Change in Account as of Dec 31, 2021 Increase/(decrease)	Accumulated Depreciation as of Dec 31, 2021
465 – Transmission Plant Mains	$288,573,484	$141,839,864
475 - Distribution Plant Mains	($288,573,484)	($141,839,864)

Classification of Regulator and Meter Installations

26. The second area of alignment is the classification of regulators and meter installations. Historically, EGD rate zone has included regulator and meter installation assets within the distribution services pipe assets (473) asset class for accounting convenience as per the USoA definition below. The Union rate zones included similar assets under the regulator and meter installations (474) asset class. The OEB USoA defines the 473 and 474 accounts as follows:

> 473. This account shall include the installed cost of service pipes, from the point at which the main is tapped to and including the meter shut off stop, whether inside or outside of the customers' premises. This includes also such service pipes paid for by the customer but for which the utility has assumed full responsibility for the maintenance and replacement of such facilities.
>
> 474. This account shall include the cost of regulators whether actually installed or held in reserve. It shall further include the cost of labour and materials used, and expenses incurred in the original installation of regulators and meters. For accounting convenience, the cost of the regulator and meter and the installation costs may be transferred annually to Account No. 473, "Services".[11]

27. Enbridge Gas is proposing to align the EGD with the Union rate zones and re-classify the installation of regulators and meters to account 474. Historically the Union rate zones held services and regulators as separate plant accounts due to the difference in the useful lives of the assets. The Union rate zones also retired regulator assets based on amortization accounting. The Union rate zones method is the preferred approach as it better aligns the assets with the actual useful life. Table 5 includes the amount proposed to be re-classed from 473 to 474 for EGD.

[11] Uniform System of Accounts for Class A Gas Utilities, April 1, 1996, pp.64-65. https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Uniform-System-of-Accounts-for-Class-A-Gas-Utilities.pdf

Table 5
Services to Regulators – Summary of Adjustments

Asset	$ Change in Account as of Dec 31, 2021, Increase/(Decrease)	Accumulated Depreciation as of Dec 31, 2021
474 - Regulator and Meter Installations	$432,971,860	$105,648,731
473 - Services	($432,971,860)	($105,648,731)

Classification of Buildings and Structures

28. The third area of alignment is the interpretation of the structures and improvement accounts. EGD buildings have been classified historically under account 472, whereas Union used both 472 and 482. The OEB USoA defines accounts 472 and 482 as follows:

> 472. This account shall include the cost of structures and related facilities used for distribution operations.
>
> 482. This account shall include the cost of structures and related facilities used for general utility operations and not recorded elsewhere.[12]

29. Several of the EGD rate zone buildings are used to support general utility operations and are not limited to distribution operations alone. Table 6 includes the buildings that are being reclassified from account 472 to account 482.

[12] Uniform System of Accounts for Class A Gas Utilities, April 1, 1996, pp.63, 68. https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Uniform-System-of-Accounts-for-Class-A-Gas-Utilities.pdf

Table 6
Structures and Improvements – Summary of Adjustments

Building	Change in Account as at Dec 31, 2021, Increase/(Decrease)	Accumulated Depreciation as of Dec 31, 2021
Toronto Victoria Park Centre (VPC)	$53,463,000	$19,270,729
Markham Technology & Operations Centre (TOC),	$36,672,000	$6,852,980
Thorold, Schmon Parkway[13]	$15,679,000	$6,391,978
Ottawa, SMOC[14]	$4,156,000	$2,962,472
Total Building Assets Reclassed	$109,970,000	$35,478,159

Classification of NGV Compressor Assets

30. The fourth area of alignment is the classification of NGV compressor assets. EGD has historically classified company owned NGV assets under account 476. Union rate zones did not have an account or approved rate as part of the Union Depreciation Study as there were no projects or assets at the time of the study. Union rate zones have since used account 487 for in-service NGV compressor assets. The OEB USoA defines accounts 476 and 487 as follows:

> 476. This account shall record the cost of compressors and associated equipment including NGV compressor equipment and associated refuelling equipment, used for distribution operations.

[13] The Thorold building was sold subsequent to the completion of the 2022 forecast and is not included in the 2024 forecast.
[14] The SMOC building was sold subsequent to the completion of the 2022 forecast and is not included in the 2024 forecast.

> 487. This account shall record the cost, including delivery, installation and inspection, of rental equipment owned by the utility installed on customers' premise that is not includable in other accounts.[15]

31. The Union rate zones assets recorded under account 487 include three yards at Union rate zone locations which have NGV compressor stations. Enbridge Gas is proposing to re-class these assets to account 476 to align with the EGD rate zone presentation and the USoA definition of the account. Table 7 includes the amount proposed to be re-classed from 487 to 476 for Union rate zones.

Table 7
NGV Compressor Assets – Summary of Adjustments

Asset	$ Change in Account as of Dec 31, 2021, Increase/(Decrease)	Accumulated Depreciation as of Dec 31, 2021
476 – Company NGV Compressor Stations	$4,662,423	$36,506
487 – Rental – NGV Stations	($4,662,423)	($36,506)

3.4. Unregulated Storage Depreciation Expense Methodology

32. Prior to amalgamation, both EGD and Union offered and sold unregulated market-based storage services and used OEB-approved unregulated storage allocation methodologies to allocate costs. The methods for calculating depreciation expense on storage assets were aligned, however a difference was identified regarding general plant assets. Union had a methodology for allocating general plant assets to unregulated storage whereas EGD did not allocate general plant assets to

[15] Uniform System of Accounts for Class A Gas Utilities, April 1, 1996, pp.66, 71-72. https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Uniform-System-of-Accounts-for-Class-A-Gas-Utilities.pdf

unregulated storage. Enbridge Gas engaged Ernst & Young LLP (EY) to assist management in its determination of the Company's harmonized unregulated storage allocation methodology. The aligned methodology for Enbridge Gas adopts the Union methodology of allocating general plant assets to unregulated storage. Further details, including impacts to 2024 Test Year depreciation expense are provided at Exhibit 1, Tab 13, Schedule 2.

3.5. Summary of Impacts of Harmonization of Depreciation Policies at Rebasing

33. Enbridge Gas is proposing a depreciation expense of $892 million for the 2024 Test Year. A comparison of the proposed depreciation rates and the provision for the 2024 Test Year is provided at Attachment 2. /u

4. Energy Transition Considerations

34. In developing the proposed depreciation rates, Enbridge Gas and Concentric considered the introduction of an Economic Planning Horizon (EPH) or truncation date to reflect the potential impact that energy transition could have on the economic life of Enbridge Gas's system.

35. Enbridge Gas and Concentric concluded that introducing an EPH is not appropriate at this time. As provided at Exhibit 1, Tab 10, Schedule 5, Section 3, there remains significant uncertainty around the impacts that energy transition could potentially have on Enbridge Gas's system. However, future depreciation studies may warrant the introduction of a regional or system wide EPH, as the energy transition unfolds and more information on the future utilization of Enbridge Gas's assets becomes available.

5. Site Restoration Costs

36. In EGD's 2014 to 2018 Custom IRM Decision[16], the OEB directed EGD to examine the issue of whether a segregated fund for SRC should be established and to present such findings in EGD's next rebasing application.

37. The directive was a result of intervenors in EGD's 2014 to 2018 Custom IRM proceeding referencing the National Energy Board's (now the Canada Energy Regulator, or CER) Land Matters Consultation Initiative (LMCI) which was underway at the same time as EGD's 2014 to 2018 IRM proceeding. The LMCI proceeding directed CER-regulated entities to start collecting amounts for future abandonment from customers and to segregate the funds collected from a pipeline company's operating funds. However, the assets in the LMCI proceeding are different than the assets held by Enbridge Gas as the CER-regulated pipelines have an expected end of life whereas the utility assets are expected to be replaced over time and remain useful. Additionally, there were no retirement costs previously collected for the CER-regulated pipelines whereas Enbridge Gas has been collecting SRC for many years.

38. To respond to the directive, Enbridge Gas conducted internal research to determine whether or not a segregated fund should be established. Enbridge Gas looked for examples of other utilities that may have considered the approach of a segregated fund for SRC. In FortisBC Energy Inc. (FEI) 2012 and 2013 Revenue Requirements and Natural Gas Rates Application, FEI investigated the practicality of using a segregated fund however ultimately did not adopt the approach. Enbridge Gas did not find any examples of other utilities using segregated funds for SRC. The net salvage approach is currently used by many utilities in North America.

[16] EB-2012-0459, OEB Decision with Reasons, July 17, 2014, pp.63-64.

39. As previously described, Enbridge Gas is collecting amounts for future abandonment within the net salvage component of the depreciation rates for the EGD and Union rate zones. These amounts are included in accumulated depreciation which results in a reduction to the PP&E component of rate base. The amounts collected are used to fund working capital requirements, which in turn reduces the need for financing and therefore has a favourable impact for customers in the form of lower rates, all else being equal.

40. Enbridge Gas agrees that there are benefits to establishing a segregated fund for SRC.
    a) A fund is a prudent approach to ensuring that money will be available when ultimate abandonment of Enbridge Gas's system is undertaken;
    b) If the money in the segregated fund is invested, positive returns on the investment may decrease the amount of SRC to be collected which would benefit ratepayers through lower depreciation rate
    c) Establishing a segregated fund would also be a means of preparing for potential future energy transition impacts.

41. However, there are also drawbacks to setting up a segregated fund for SRC:
    a) Currently, the net salvage collected is a credit to rate base (recorded as part of accumulated depreciation). Establishing a fund would increase rate base, by eliminating the net salvage amounts collected from accumulated depreciation, which in turn would increase the cost of capital and increase revenue requirement. As an example, if the December 31, 2021, SRC liability balance of $1.5 billion was deposited into a segregated fund, rate base and

revenue requirement would increase by $1.5 billion and $93 million[17] respectively. The annual increase in revenue requirement thereafter is estimated to be $3.1 million;

b) Administrative costs required to set up, monitor and maintain the fund, and the administrative burden to access the funds would also increase costs;
c) Tax issues associated with establishing a fund are complex and would require significant legal and tax involvement to resolve;
d) Enbridge Gas has not identified any precedents in which a utility has voluntarily set up a segregated fund for SRC costs; and
e) Enbridge Gas does not expect a large-scale retirement of assets and anticipates that assets will be in use and useful for many years to come.

42. In addition to the above drawbacks, participants in the Customer Engagement Survey, as provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, page 9, were asked whether Enbridge Gas should have the flexibility to use reserves to avoid borrowing money. Participants expressed support in giving Enbridge Gas flexibility if it means potential savings for customers.

43. Enbridge Gas concludes that it is in the best interest of customers not to set up a segregated fund for SRC amounts at this point in time. As provided at Exhibit 1, Tab 10, Schedule 5, Enbridge Gas believes its system will be a key contributor to Ontario’s ability to achieve net-zero. Additionally, Enbridge Gas does not anticipate that large sections of its system will be retired in the foreseeable future. Enbridge Gas may reconsider the establishment of a segregated fund in the future, in

[17] Assumes a SRC liability balance of $1.5 billion, a debt/equity ratio of 64/36, ROE of 8.34% and a tax gross up on ROE of 73.5%.

conjunction with the implementation of an EPH, as more information about the potential impact of energy transition becomes available.

6. Depreciation Schedules

42. Detailed depreciation schedules for the 2019 to 2024 period by plant account and rate zone are provided at Attachment 3.

2021 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES
APPLICABLE TO NATURAL GAS PLANT IN SERVICE

Prepared for Enbridge Gas Inc.
October 2022

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October 14, 2022

Enbridge Gas Inc.
500 Consumers Road
North York, ON
M2J1P8

Attention: Danielle Dreveny
Manager, Capital FP&A

Dear Ms. Dreveny;

Pursuant to your request, we have conducted a depreciation study related to the gas transmission, distribution and storage systems and related general plant of Enbridge Gas Inc. Our report presents a description of the methods used in the estimation of depreciation and net salvage, the statistical analysis of service life and the summary and detailed tabulations of annual and accrued depreciation.

We gratefully acknowledge the assistance of Enbridge Gas personnel in the completion of the review.

Should you have any questions or concerns, please do not hesitate to contact me directly at 587.997.6489

Yours truly,

Concentric Advisors, ULC

Larry E. Kennedy
Senior Vice President

Amanda Nori
Project Manager

LEK/ta
Project: 70079

TABLE OF CONTENTS

SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to Enbridge Gas Inc.'s ("EGI" or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to the gas distribution, transmission, storage and general plant accounts, as of December 31, 2021. The purpose of the study is to determine the annual depreciation accrual rates and amounts applicable to the original cost of gas utility plant, as of December 31, 2021. The Curriculum Vitae for Larry Kennedy has been attached as Appendix 3 to this report.

Enbridge Gas Distribution Inc. ("EGD") amalgamated with Union Gas Limited ("Union") to form EGI since the last depreciation studies for each company were completed. In this study the assets have been combined and depreciation parameters have been developed and depreciation rates calculated on the combined asset groups. As such, depreciation parameters, methodologies, and procedures from both the Union and EGD systems have been reviewed. The recommendations within this report are viewed by Concentric to be the most appropriate recommendations to be applied to the combined asset groups. This report recommends conversion to the use of the Equal Life Group ("ELG") procedure. The ELG procedure is similar to the Generation Arrangement procedure used in the previous Union study and represents a change from the Average Life Group for the EGD assets. Additionally Concentric recommends the use of amortization accounting for a small number of general plant asset groups, which represents a change in method for the EGD general plant assets. Concentric also recommends the use of the Constant Dollar Net Salvage ("CDNS") methodology of calculating net salvage accruals, as was used in the previous EGD study, and represents a change in salvage method for the Union assets.

The depreciation rates were applied on a Remaining Life basis, based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets. Variances between the calculated accrued depreciation and the book accumulated depreciation, as at December 31, 2021, are amortized over the composite remaining life of assets.

Concentric recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service, as of December 31, 2021, summarized in Table 1 in Section 5 of this report by account detail. Supporting data and calculations are provided as well.

Finally, this study results in an annual depreciation expense accrual related to the recovery of original cost and net salvage requirement of $786.5 million, when applied to depreciable plant study balances, as of December 31, 2021, of $21.7 billion. The study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

Plant Group	Original Cost	Annual Accrual	
Local Storage Plant	$33,641,115	1.16%	$390,705
Underground Storage Plant	$1,297,148,055	2.91%	$37,704,129
Transmission Plant	$4,449,654,239	2.33%	$103,839,505
Distribution Plant	$14,994,747,798	3.74%	$560,985,714
General Plant	$918,099,975	9.10%	$83,536,220
TOTAL DEPRECIABLE PLANT STUDY BALANCE	**$21,693,291,183**	**3.63%**	**$786,456,273**

SECTION 2

2 BASIS OF THE UPDATE

2.1 Scope

Concentric has been retained by EGI to develop reasonable and appropriate depreciation amounts based on plant in service as of December 31, 2021 and applied specifically to plant in service as of December 31, 2021 as summarized by Table 1. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates. The rates and amounts are based on the Straight-Line method of depreciation, incorporating the ELG procedure applied on a Remaining Life basis.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Concentric has determined an amortization amount to adjust the present booked accumulated depreciation variance with the calculated accrued depreciation ("theoretical reserve") over the composite remaining life of each account. This adjustment mechanism, whether determined separately as an amortization amount or incorporated in the calculation of remaining life accruals, is widely accepted throughout North America. An explanation of the monitoring of the accumulated depreciation reserve and the calculation of the true-up provision is presented on page 4-4 of this report.

The Straight-Line method, ELG procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America and is described in detail in Section 3.1. Amortization accounting is used for certain accounts because of the disproportionate plant accounting effort required to process retirements in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these types of accounts.

2.2 Plan of Study

This study is presented in the following order:

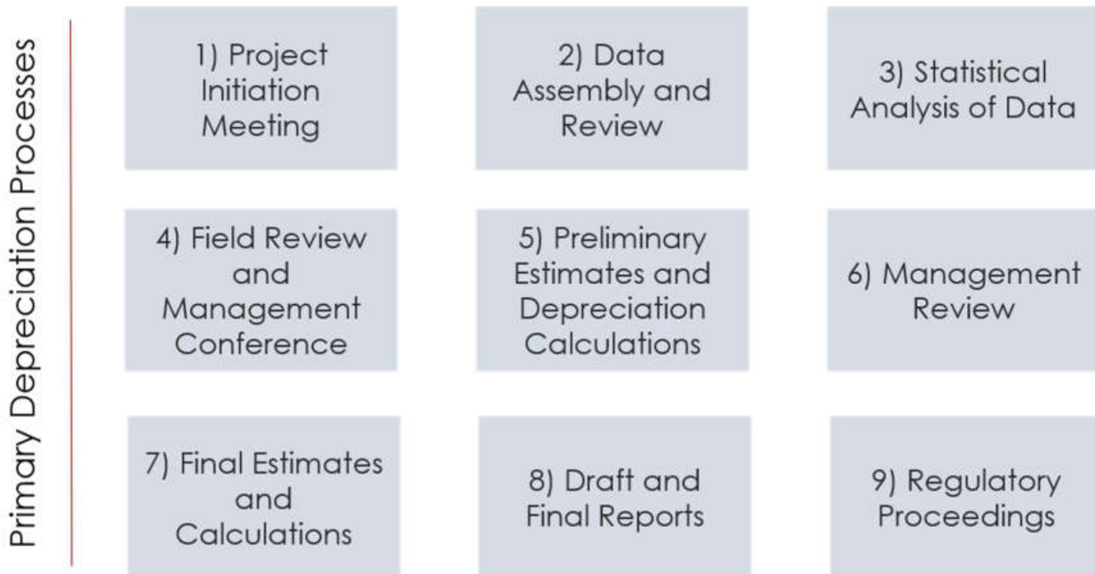
Section 1:	Study Highlights, presents a brief summary of the depreciation study and results
Section 2:	Contains statements with respect to the plan and the Basis of the Update
Section 3:	Development of the Required Depreciation Rates, presents descriptions of the methods used and factors considered in the service life study
Section 4:	Calculation of Annual and Accrued Depreciation, presents the methods and procedures used in the calculation of depreciation
Section 5:	Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Table 1.
Section 6:	Presents the results of the Retirement Rate Statistics
Section 7:	Presents the results of the Net Salvage Study
Section 8:	Presents the results of the Detailed Depreciation Calculations
Section 9:	Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis
Section 10:	Estimation of Net Salvage discusses the methodology used in calculating net salvages

2.3 Depreciation

A full and comprehensive depreciation study includes the following components:

1. supported recommendations regarding Average Service Life estimates for each account;
2. supported recommendations regarding estimated Net Salvage requirements for each account;
3. selection of an appropriate grouping procedure;
4. detailed calculation of the depreciation rate utilizing the estimated Average Service Life and Net Salvage requirements; and
5. a document explaining the procedures followed and justifying the results in a format suitable for submission to senior management and regulatory authorities.

A diagram of the nine primary processes followed by Concentric in the development of the depreciation study is provided below. Each of the steps is undertaken by Concentric using proprietary software.



2.4 Information Provided by EGI

EGI has provided Concentric with the required information, as of December 31, 2021. Due to the amalgamation of Union and EGD, historical data was obtained from both companies. This information from both companies was consolidated from the information compiled from the plant accounting records to produce a consolidated version of the following:

- Current balances by vintage year for each account (aged balances) through December 31, 2021. The balances provide the amount of investment sorted by installation year. This file is only inclusive of plant in service and does not include any retirements;
- retirement transactions for all accounts from 1948 through December 31, 2021. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired, and the original cost of the asset being retired; and
- cost of removal and gross salvage transactions for all accounts requiring the recovery of net salvage through December 31, 2021. The transactions include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.

2.5 Data Reconciliation

The above data was reviewed and reconciled to Company control schedules to ensure accuracy and reasonableness in use of the calculations developed in this study. These checks include:

- that the surviving investment by account equals (or can be reconciled to) the Company's gross plant in service and accumulated depreciation ledger balances;

- that the surviving investment in each vintage is not negative. In other words, this check confirms that the sum of retirements from any given vintage have not exceeded the amount of plant additions to the vintage; and
- that any adjusting transactions are properly accounted for within the databases.

2.6 Account Harmonization

EGI will implement depreciation rates jointly between the Union and EGD assets. Historically there have been small differences between the categorization and account policies of Union and EGD. These differences are caused by differences in the types of assets in service or in the manner in which assets were used. For example, Union has historically had a large transmission system, while EGD has categorized all assets as distribution. As such Concentric has provided a single depreciation study applicable to all assets of the EGI system.

In order to provide a consolidated depreciation rate, assets from both utilities were combined into single accounts for the purposes of this study. Accounts were grouped (or re-categorized if needed) based on similar asset profiles, average service lives, and Iowa curves. The depreciation rates and parameters discussed in this report are based on the accounting records incorporating this harmonization. Changes to the EGI accounting system will not be made until approval of this study is granted.

Harmonized EGI Account	UGL Account	EGD Account
LOCAL STORAGE PLANT		
442.00 - STRUCTURES AND IMPROVEMENTS	442.00 - STRUCTURES AND IMPROVEMENTS	
443.01 - HOLDER - STORAGE TANK	443.01 - GAS HOLDERS - STORAGE TANK	
443.02 - HOLDER EQUIPMENT	443.02 - GAS HOLDERS - EQUIPMENT	
UNDERGROUND STORAGE PLANT		
451.00 - LAND RIGHTS INTANGIBLE	401.00 - FRANCHISES AND CONSENTS, 451.00- LAND RIGHTS	451.00 - LAND RIGHTS INTANGIBLE
452.00 - STRUCTURES AND IMPROVEMENTS	452.00 - STRUCTURES AND IMPROVEMENTS	452.00 - STRUCTURES AND IMPROVEMENTS
453.00 - WELLS	453.00 - WELLS AND LINES	453.00 - WELLS
454.00 - WELL EQUIPMENT		454.00 - WELL EQUIPMENT
455.00 - FIELD LINES	453.00 - WELLS AND LINES	455.00 - FIELD LINES
456.00 - COMPRESSOR EQUIPMENT	456.00 - COMPRESSOR EQUIPMENT	456.00 - COMPRESSOR EQUIPMENT
457.00 - REGULATING AND MEASURING EQUIPMENT	457.00 - MEASURING AND REGULATING EQUIPMENT	457.00 - MEASURING AND REGULATING EQUIPMENT
TRANSMISSION PLANT		
461.00 - LAND RIGHTS INTANGIBLE	461.00 - LAND RIGHTS	
462.00 - COMPRESSOR STRUCTURES AND IMPROVEMENTS	462.00 - STRUCTURES AND IMPROVEMENTS	
463.00 - MEASURING AND REGULATING- STRUCTURES AND IMPROVEMENTS	462.00 - STRUCTURES AND IMPROVEMENTS	
464.00 - EQUIPMENT	462.00 - STRUCTURES AND IMPROVEMENTS	
465.00 - MAINS	465.00 - MAINS - METALLIC	
466.00 - COMPRESSOR EQUIPMENT	466.00 - COMPRESSOR EQUIPMENT	
467.00 - MEASURING AND REGULATING EQUIPMENT	467.00 - MEASURING AND REGULATING EQUIPMENT	
DISTRIBUTION PLANT		
471.00 - LAND RIGHTS INTANGIBLE	471.00 - LAND RIGHTS	471.00 - LAND RIGHTS
472.00 - STRUCTURES AND IMPROVEMENTS	472.00 - STRUCTURES AND IMPROVEMENTS	472.00 - STRUCTURES AND IMPROVEMENTS
473.01 - SERVICES - METAL	473.01 - SERVICES - METALLIC	473.00 - SERVICES
473.02 - SERVICES - PLASTIC	473.02 - SERVICES - PLASTIC	473.00 - SERVICES
474.00 - REGULATORS	474.00 - REGULATORS	
475.00 - MAINS - ENVISION		475.EN - MAINS - ENVISION
475.21 - MAINS - COATED & WRAPPED	475.01 - MAINS - METALLIC	475.10 - MAINS - CAST IRON, 475.20 - MAINS BARE STEEL, 475.21 - MAINS COATED STEEL
475.30 - MAINS - PLASTIC	475.02 - MAINS - PLASTIC	475.30 - MAINS - PLASTIC
476.00 - COMPANY NGV COMPRESSOR STATIONS		476.00 - COMPANY NGV COMPRESSOR STATIONS
477.00 - MEASURING AND REGULATING EQUIPMENT	477.00 - MEASURING AND REGULATING EQUIPMENT	477.00 - MEASURING AND REGULATING EQUIPMENT
477.01 - CUSTOMER M&R EQUIPMENT	474.01 - REGULATOR AND METER INSTALLATIONS	
478.00 - METERS	478.00 - METERS	478.00 - METERS
GENERAL PLANT		
482.00 - STRUCTURES AND IMPROVEMENTS	482.00 - STRUCTURES AND IMPROVEMENTS	
483.00 - OFFICE FURNITURE AND EQUIPMENT	483.10 - OFFICE FURNITURE AND EQUIPMENT	483.01 - OFFICE EQUIPMENT, 483.02 - OFFICE FURNISHINGS
484.00 - TRANSPORTATION EQUIPMENT	484.00 - TRANSPORTATION EQUIPMENT	484.00 - TRANSPORTATION EQUIPMENT, 484.01 - CO FLEET NGV KITS, 484.02 - CO FLEET NGV CYLINDERS
485.00 - HEAVY WORK EQUIPMENT	485.00 - HEAVY WORK EQUIPMENT	485.00 - HEAVY WORK EQUIPMENT
486.00 - TOOLS AND WORK EQUIPMENT	486.01 - TOOLS AND OTHER EQUIPMENT	486.00 - TOOLS & WORK EQUIPMENT
487.70 - RENTAL - REFUEL APPL		487.70 - RENTAL - VRA's, 487.9 - NGV RENTAL CYLINDERS
487.80 - RENTAL - NGV STATIONS		487.80 - NGV STATIONS

Harmonized EGI Account	UGL Account	EGD Account
488.00 - COMMUNICATION STRUCTURES AND EQUIPMENT	488.01 - COMMUNICATION EQUIPMENT	488.00 - COMMUNICATION EQUIPMENT
490.00 - COMPUTER EQUIPMENT	483.20 - OFFICE EQUIPMENT - COMPUTERS	490.00 - COMPUTER EQUIPMENT
490.30 - COMPUTER EQUIPMENT - WAMS		WAMS
491.01 - SOFTWARE ACQUIRED INTANGIBLES	483.20 - OFFICE EQUIPMENT - COMPUTERS	491.01 - SOFTWARE ACQUIRED
491.02 - SOFTWARE DEVELOPED INTANGIBLES	483.20 - OFFICE EQUIPMENT - COMPUTERS	491.02 - SOFTWARE DEVELOPED
491.03 - CIS ACQUIRED SOFTWARE		491.03 - CIS SOFTWARE ACQUIRED
491.04 - WAMS		WAMS

SECTION 3

3 DEVELOPMENT OF THE REQUIRED DEPRECIATION RATES

3.1 Depreciation

The development of the depreciation calculations requires the input of an average service life, a retirement dispersion curve (i.e. Iowa curve) and net salvage recommendations (i.e. the depreciation parameters). Additionally, to complete the depreciation calculations, the calculation methods must be established. Specifically, the selection of the depreciation method must establish three types of additional input:

1. the choice of a depreciation method;
2. a basis upon which to apply the method, and
3. in the case of group assets, a procedure to use in grouping the assets.

In this study, the depreciation rates for EGI have been calculated in accordance with the Straight-Line method, the ELG procedure and applied using the Remaining Life technique where any accumulated depreciation variances are trued-up within the depreciation rate calculations over the composite remaining life of each account.

Depreciation, as applied to depreciable plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art and changes in demand and requirements of public authorities.[1]

When considering the action of the elements, the average service life and net salvage calculations have considered large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utilities has been influenced by events including:

- forest fires;
- earthquakes;
- tornadoes;
- ice storms;
- wind-storms;
- large scale flooding;
- fires;
- lightning;
- intentional actions of third parties;
- hoar frost; and
- other natural forces of nature.

[1] Federal Energy Regulatory Commission, Part 201 – Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service - that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

The calculation of annual and accrued depreciation based on the Straight-Line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed below.

3.1.1 Study Depreciation Methods and Procedures

3.1.1.1 Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, Average Life Group ("ALG") and Equal Life Group ("ELG"). The Generation Arrangement, discussed below, is a lesser used procedure and is similar in nature to ELG.

3.1.1.2 Average Life Group and Equal Life Group Procedures

The difference in calculation of depreciation expense derived from ELG and ALG can best be explained with the use of a simple example.

Assume one plant account with a total cost of $2,000 is comprised of two subgroups of assets, each with an original cost of $1,000. The first group has a life of 5 years, while the second group has a life of 15 years.

Under both procedures the average life of this plant account would equal 10 years (15 + 5)/2. With the ALG procedure this average life would be used to determine the depreciation accruals for the first 5 years as follows:

($2,000 / 10 years) = $200 per year

The accrual for years 6 through 15 would be as follows:

($1,000 / 10 years) = $100 per year

Under the ELG procedure, the expense for each sub group is determined and then added together. Therefore for the first 5 years, the accrual would be as follows:

($1,000 / 5 years) + ($1,000 / 15 years) = $267 per year.

The accrual for years 6 through 15 would be as follows:

($1,000 / 15 years) = $67 per year.

The following table sets out the differences in the two methods:

Average Life Group Procedure				Equal Life Group Procedure			
Year	Accruals ($)	Retirements ($)	Acc. Deprn Balance ($)	Year	Accruals ($)	Retirements ($)	Acc. Deprn Balance ($)
1	200		200	1	267		267
2	200		400	2	267		534
3	200		600	3	267		801
4	200		800	4	267		1,068
5	200	1,000	0	5	267	1,000	335
6	100		100	6	67		402
7	100		200	7	67		469
8	100		300	8	67		536
9	100		400	9	67		603
10	100		500	10	67		670
11	100		600	11	66		736
12	100		700	12	66		802
13	100		800	13	66		868
14	100		900	14	66		934
15	100	1,000	0	15	66	1,000	0

It should be noted from the table that overall, both methods will recover the same original cost, however, there are two key differences. First, using the ALG procedure, after the first 5 years, no depreciation has been collected for the asset remaining in service. Essentially, the concept of depreciation expense matching the assets providing service is not met. With the ELG procedure, this problem is remedied and after the retirement at year 5 of the shorter life asset, an appropriate provision for the first 5 years of service on the longer living asset is accumulated ($67 X 5 years = $335). Under ELG all current users are sharing the cost of all assets in service.

Secondly, under ALG the customers using the last remaining assets are required to pick up an adjustment for the under accrual of depreciation expense during the early years of the account. This inter-generational inequity may potentially result in a situation at EGI where users in the later years of the system bear the cost of under accruals which benefited earlier users of the system.

Effectively, later users of the system would be subsiding previous users. With potential changes in the utility industry, future users of the facilities may be different from the current system users. This lack of stability may magnify the inter-generational inequity of the ALG procedure.

3.1.1.3 Generation Arrangement

The Generation Arrangement is a depreciation process that was commonly used in the telephone industry and that may be used to assist in the blending of past retirement experience with the expectations of future life characteristics. In its most pure form, the Generation Arrangement can be used with the ELG method; however, in the more typical usage, and the manner in which Union has historically used it, the Generation Arrangement is a stand-alone depreciation method used to calculate the annual depreciation accrual rate and amount.

An excerpt from "Public Utility Depreciation Practices" as published by the Subcommittee on Depreciation of the Finance and Technology Committee of the National Association of Regulatory Utility Commissioners has been attached to this report as Appendix 2. This appendix details the calculations underlying the Generation Arrangement.

The largest difference between the Generation Arrangement and other depreciation methodologies is the role of the historical retirement transactions. ELG and ALG do not consider historical retirements in the determination of a depreciation rate, instead, historical retirements are only considered through the selection of the average service life and Iowa curve. Remaining Life ELG and Remaining Life ALG calculate depreciation on the net book amount, calculated as total plant in service less accumulated depreciation. Generation Arrangement ignores the accumulated depreciation amount and instead calculates the depreciation rate through the use of historical retirements and additions. While this should theoretically end up with a very similar outcome to Remaining Life ELG, in practice the accumulated depreciation fund is often skewed by historical true ups and other events over the long history of the account.

The necessity of actual historical experience leads to the Generation Arrangement being impractical for utilities without recorded retirements going back to the inception of the account. It is possible to simulate retirement transactions using generally accepted methods, however the resulting depreciation rate becomes closer to a whole life calculation in this circumstance. In situations where historical records are unavailable, the ELG method with the use of the remaining life procedure results in a more accurate depreciation rate.

While undergoing the selection of a depreciation methodology for this study, Concentric calculated the depreciation expense in a single EGI account using both the Generation Arrangement and ELG remaining life, in order to test the difference between ELG and Generation Arrangement. The EGD services account, with an original cost of $3.3 billion was calculated using the Iowa 55-S1. For ease of calculations, there was no net salvage used. The Generation Arrangement resulted in a depreciation amount of $61.4 million, while the ELG remaining life resulted in an amount of $63.6 million, a difference of 3.6 percent. The calculation summary of both is attached as Appendix 2.

While there is a small increase in depreciation expense when using ELG versus Generation Arrangement, the ELG calculations better match the actual historical and future experience of the plant in service. The lack of historical retirement experience for Union assets requires the Generation Arrangement to use simulated retirement data, which results in a less accurate depreciation rate than either the ALG or ELG calculations.

3.1.1.4 Recommendation of Group Procedure

The EGD depreciation studies have historically been completed using the ALG procedure, while the Union studies have used the Generation Arrangement procedure. As previous studies were completed using different procedures, it was essential to review the procedures and recommend a single best option for the combined assets. As ELG more accurately reflects the actual life of the assets used, Concentric is recommending the movement to ELG at this time.

The ELG procedure was specifically developed for use by rate regulated companies. The ELG procedure was popularized in a publication of the Iowa State University entitled "Depreciation of Group Properties – Bulletin 155" by Robley Winfrey in 1942. At the time of the publication of Bulletin 155, what is currently known as the Equal Life Group Procedure was at that time published as the "Unit Summation" Procedure. Initially, the use of the ELG procedure was somewhat limited because of the extremely large number of calculations that are required when this procedure is used. However, in the 1970's and more so in the 1980's this method became more popular due to the increased use of computerized software, rendering the number of calculations to be a non-issue. At that time, many regulated telephone companies adopted the use of the ELG procedure, including virtually all of the regulated telephone companies that were regulated by the Canadian Radio and Telecommunications Commission (CRTC). In the late 1980's many other utility sectors began to adopt the use of the ELG procedure throughout North America.

The use of the ELG Procedure enhances the generational equity to all toll payers when all relevant costs are considered. Furthermore, use of the ELG Procedure provides ratepayers an enhanced matching of the depreciation expense component of the revenue requirement to the consumption of the service value of assets providing utility service. As indicated by Robley Winfrey in Bulletin 155, "the unit summation procedure of the present worth method is shown to be the only mathematically correct method".

This study calculates the annual and accrued depreciation using the Straight-Line method and ELG procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Concentric has determined an amortization amount to adjust the present variance with the calculated accrued depreciation (theoretical reserve) over the composite remaining life of each account.

3.2 Economic Planning Horizon and Decarbonization

3.2.1 Concept of Economic Planning Horizon

The life of long-lived assets such as those comprising EGI's system can be restricted not only by physical forces of retirement such as wear and tear and physical deterioration, but also and to a much greater extent, by economic forces of retirement. Specifically, the changing North American marketplace for natural gas demand and the rapidly emerging trend of decarbonization legislation may have a significant impact on the estimated service lives of the EGI system.

There are several factors affecting the economic viability of the EGI system. Long life assets, such as natural gas storage, transmission and distribution systems, are subject to a number of different forces of economic retirement, including changes in legislation constricting the use of carbon-based fuels.

The concept referred to with the terms "economic planning horizon", "economic life", or "truncation date" (each of which have similar meaning within depreciation literature) is one of the parameters that can be used to set depreciation rates that accurately reflect the annual consumption in service value. Appropriate depreciation rates also help to ensure that both long term intergenerational equity among customers and a reasonable opportunity for the recovery of investment are achievable.

The pipeline system will experience both interim and final retirement activity. Interim or ongoing retirements represent those retirements described by the interim survivor curve, which is commonly referred to as the Iowa curve. Terminal or final retirements represent those retirements described by the truncation of the interim survivor curve at the truncation date (or economic life). Interim retirements include retirements related to replacements that are primarily caused by wear and tear, deterioration, and technological obsolescence, i.e. the replacement of an item of equipment with a newer item with greater functionality. Terminal retirements include retirements related to the final abandonment of major components of the system caused by the economic obsolescence of the system. Such retirements are not expected to occur all at once. Rather, it is anticipated that there will be a relatively restricted period during which these major retirements will occur. In order to readily perform the mathematical calculations of average and remaining life, the timing of the terminal and final retirements is represented by a single point, the economic planning horizon (or life span date).

3.2.2 Decarbonization

On June 8th, 2016, the Office of the Ontario Premier Kathleen Wynne released its plan for a "low-carbon future" in its "Climate Change Action Plan". The action plan outlined Ontario's plan to begin phasing out natural gas for heating by providing incentives to retrofit buildings. This plan was replaced on November 29, 2018 with the Made-in-Ontario Environment Plan released by Premier Doug Ford. The Made-in-Ontario Environment Plan commits to reducing greenhouse gas emissions to 30 percent below 2005 levels by 2030.

EGI has responded to the Made-in-Ontario-Plan with a number of low carbon strategies, including a pilot program to test the blending of hydrogen, a voluntary RNG program, and the filing of a new DSM 2022-2027 Plan. The pilot program will provide EGI with a better understanding of the future use of hydrogen within the gas distribution system. These strategies will enable EGI to better plan for a lower carbon future.

In addition to the Made-in-Ontario Environment Plan, the Canadian federal government has passed a number of acts and regulations intended to bring Canada in line with Paris Accord. Prime Minister Justin Trudeau signed the Canadian Net-Zero Emissions Accountability Act on June 30, 2021. This act sets the goal of 2030 greenhouse gas emissions being 40-45 percent below 2005 levels by 2030. Further, there is the requirement that greenhouse gas emission goals be set for 2035, 2040, and 2045 at least ten years in advance. Ultimately, the goal is for Canada to attain net-zero emissions by 2050. It is noted that both the cities of Hamilton and Toronto have made net-zero commitments independent of federal or provincial mandates.

The federal government notes that the movement to hydrogen may be an important step in order to achieve a net-zero emissions target by 2050. The federal government has created a fund intended to increase production of low-carbon fuels, including hydrogen and renewable natural gas. The use of hydrogen and renewable natural gas may have a significant impact on the business of EGI in the foreseeable future.

3.2.3 Economic Planning Horizon Recommendations

While there is strong evidence that the future of natural gas in Ontario may be impacted by climate change legislation, it is still unknown to what extent this change will impact EGI's system. The introduction of hydrogen may have a life lengthening impact on the system if it is determined that hydrogen is a sustainable replacement fuel. The same may be true of renewable natural gas or other low carbon fuels. However, it may also be true that the move from carbon based fuels necessitates a greater electrification, in which case there may be a life shortening impact on some or all of the EGI system.

The future growth and retirement programs of the EGI system may be significantly different than the retirement patterns witnessed in the past. While future retirements that are caused by physical forces of retirement such as wear and tear and changes in technology of the assets will continue, it is reasonable to anticipate that the utilization of large groups of assets may change due to the implementation of climate change legislation. Consistent with the reduction in the utilization of the assets, it could be assumed that large scale retirement of assets may be required in the periods between now and 2050.

Common depreciation practice is to deal with the anticipated large scale retirements through the introduction of an economic planning horizon within the depreciation rate calculations. However, at this time the future impacts of the relevant climate change legislation have not been sufficiently studied, nor have specific programs been put into place that would provide indications of the changes in the utilization levels. Concentric views that additional study of the changes is required before the introduction of a Life Span date for the EGI system into the depreciation rate calculations. While such an introduction will cause a significant increase in the depreciation rate, Concentric notes that future depreciation studies of the EGI system may require the introduction of an EPH into the depreciation rate calculations. Concentric has attached Appendix 1 that shows the depreciation rate calculations using the same recommended depreciation parameters as the current study, with the introduction of a 2050 EPH. While Concentric is not recommending this move at this time, the calculations are provided as an example of what would be expected if a 2050 EPH were approved.

3.3 Estimation of Survivor Curves and Net Salvage

3.3.1 Survivor Curves

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as Iowa type curves. The Iowa curves *"…were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups* *were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."*[2] The Iowa curves are described as L-type (i.e. left-moded), R-type (i.e. right-moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin-moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion known as the Residual Measure. This Residual Measure is based on a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely used practice of fitting Iowa curves up to one percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

A discussion of the general concept of survivor curves and retirement rate method is presented in Section 9.

3.3.2 Net Salvage Methodology

There has been considerable attention paid to how future plant decommissioning, site restoration or costs of removal of assets for interim (non-terminal) retirements can be estimated, collected and reported. The increased scrutiny depreciation studies are getting is in large part due to how costs will be collected at the end of a project's economic or physical life. The long timelines between the installation of assets and their decommissioning, the increased emphasis on environmental health and safety as well as the increased risk of decarbonization and other macro economic factors are increasing both the magnitude and likelihood of costs of removal.

There are several ways that funds can be allocated, each with their own advantages and disadvantages. The four most common methods are described below:

1. Pay as you go method. Any costs of removal or rehabilitation due to interim or terminal retirements are charged as operating expenses at the time they are incurred. This method is the most straightforward. Its advantages and disadvantages stem from its simplicity of implementation. Understanding the timing and magnitude of expenses forms the basis for the remaining methods.

[2] Robley Winfrey, Statistical Analyses of Industrial Property Retirements, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

Pay as you go method	
Pros	Cons
Simple to implement	Retirements, expansions and closure costs are not levelized, leading to large spikes in capital outlays and ensuing volatility in rates.
Easy to quantify, no future escalation or future scope estimates required.	Wind up costs are incurred usually at the end of a project's life in large amounts. This makes it difficult to match costs of the asset to its benefits.
Easy to understand by interested parties.	Subsidizes customers that use the asset by transferring the costs of removal onto users at the time of terminal retirements.

2. Traditional approach. Net salvage is estimated as a percentage of the original cost to be depreciated and accumulated over the lifetime of an asset. Net salvage is collected as an added expense with depreciation over the life of the asset and charged against accumulated depreciation at the time of incurring any removal costs. The traditional method attempts to forecast the pay as you go method and evenly distribute it in nominal, or year of expenditure dollars. This method is a charge against rate base and serves to depreciate original costs.

Traditional method	
Pros	Cons
Relatively simple to implement.	Costs of removal need to be estimated with historical data that may not be indicative of future scope and costs.
Levelizes costs over the life of the asset and is more equitable across generations of users.	Implementation can lead to rate shock if introduced late in the life of the project(s).
Attempts to incorporate inflationary pressures by recording historical inflation and extrapolating salvage rates to future original costs.	Acts as depreciation charge against future original costs and can erode rate base prematurely, depending on the distribution of capital expansions.
Adopted by US GAAP and IFRS accounting procedures.	More affected by harder to predict technological improvements and market disruptions which alter costs and timing of project windup.

3. Constant Dollar Net Salvage ("CDNS"). This method establishes a baseline of costs of removal expressed as the purchasing power of a common year of reporting. Historical estimates are inflated by using a prescribed labour and materials inflation rate to the year of retirement using remaining life calculations. It then accounts for any return on capital by discounting back the future inflated salvage costs to a baseline year at an accepted risk-free cost of capital.

As in the Traditional Method, net salvage is collected as an added expense with depreciation over the life of the asset and charged against accumulated depreciation at the time of incurring any removal costs. Given the upfront collection of historical costs subject to inflationary pressures, the CDNS method acknowledges cost of capital and discounts to a base year. The CDNS method tries to predict more moving pieces that are subject to future costs of material, labour and capital.

Constant Dollar Net Salvage method	
Pros	Cons
Adjusts for upfront levelized collection by discounting to a base year.	Methodology relies on more estimates of future inflation and future cost of capital and that are harder to predict and subject to debate.
Attempts to have more customer equity by passing on the benefit of any return of capital.	Relies on calculations that are not as transparent to the wider public.
Incorporates more rigor on the estimate of inflationary pressures and future cost of capital. Ties to other components of revenue requirements.	Applies a net salvage estimate for all vintage years to come up with inflated terminal year costs.
Has precedent with the adoption by some jurisdictions such as the OEB.	Assumes equal cost of capital and inflation for short duration lives and newer technology vintages.

4. Capitalized as part of replacement assets. This method collects the costs of removal as part of the capital costs of new assets that replace the older vintages. The capitalizing approach assumes there will be future installations that are closely linked to prior means of delivering the same service. One way of mitigating this risk is to separate the depreciation charges of the original costs from what will ultimately be a cost of removal obligation.

Capitalized as part of replacement assets method	
Pros	Cons
Simpler approach than having to estimate future costs and how they may escalate.	Methodology shifts the costs of removal on to the customers of the new installations.
Does not have to incorporate the historic costs of the decommissioned assets.	Assumes that older projects will have newer projects to replace them, shifting costs on to fewer viable options in the case of obsolescence or demand destruction.
Decommissioning costs coincide with near term project RFPs and are less subject to estimating bias.	Inflates the costs of more efficient newer technology, rendering them less competitive.

Meets some recognized accounting standards, like IFRS.	Increases the risk profile and cost structure of newer installations as they bear the decommissioning costs of prior generations.

In EB-2012-0459, EGD filed a Net Salvage Study[3] outlining alternatives regarding net salvage percentage calculation procedures and recommended the use of a Constant Dollar Net Salvage ("CDNS") approach. Union has historically calculated net salvage using the traditional method. As the two companies require a singular approach to the recovery of net salvage, Concentric recommends the continuation of the CDNS method for EGI as it provides an appropriate allocation between the inflation adjusted net salvage requirement and the net salvage expense collected from ratepayers for utilities similar to EGI. Further, as the OEB has approved the CDNS methodology in EB-2012-0459 for the EGD assets, the recommendation of CDNS does not represent a change for many of the assets. It is simply a continuation of the currently approved methodology for these assets.

3.3.3 Constant Dollar Net Salvage

There are two components to the development of an appropriate future net salvage percentage for mass property accounts. Firstly, an estimate of the current net cost of removal of facilities is developed. The ratio of net salvage costs to the original cost of plant retired is developed and used as one indicator of the current estimated cost of removal. However, as the plant is removed a number of years following its installation, the cost of removal is usually greatly increased due to the impacts of inflation. In particular, the cost of removal is almost exclusively labour-related. The inflationary pressures of the Ontario labour market, due to numerous and unique labour fluctuations have a dramatic impact on the net cost of removal percentages. As such an historic ratio developed by comparing cost of removal expenditures to original cost dollars retired has an inherent level of inflation built in, however the inherent assumption is that the future inflationary trend will mirror the historic trend.

Once the historic indications of net costs of retirement are determined, the historic indications can be normalized to a current cost base, providing for an ability of the depreciation analyst to compare the historic indications of the net costs to remove plant, to the costs of the engineering projects currently being undertaken, or planned to be undertaken in the near future. However, it is normal to make adjustments to the historic indications and in many circumstances the historic indications of net salvage costs are adjusted to reflect the projects currently underway.

The second component required in the future estimation of costs of removal, is to determine the cost required at the time of forecast retirement. Once the current estimate of the net costs of removal is established, the current estimate needs to be adjusted to recognize the impacts of inflation over the period from the current time, to the estimated remaining life of the account. For the purposes of this study a future inflation rate of 2.0%, consistent with the Bank of Canada long-term target, was used in the calculations included in this report.

[3] EB-2012-0459, Exhibit D2, Tab 1, Schedule 1, June 2013

In order to recognize that the funds collected in current periods will not be expensed until potentially many years into the future, a discount calculation back to present day is required. In this manner, the fact that the utility has received the benefit of the funds as working capital through the inclusion of the requirement into the current period revenue requirements is recognized. Concentric discounted the future requirements by EGI's current credit adjusted risk free (CARF) rate at the time the calculation was completed of 3.78%, rounded to 3.75%. The use of a CARF is consistent with the discount rates mandated by accounting standards for Asset Retirement Obligations (ARO) for financial statement disclosure, and for estimating the discount rate in Securitization calculations. The use of a CARF rate is consistent with the evidence of interveners in the last Incentive Regulation Proceeding and applications made by Group 1 pipelines to the Canadian Energy Regulator (CER). As such Concentric included a discount rate of 3.75% in the CDNS calculations.

3.3.4 Survivor Curve and Net Salvage Judgments

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the natural gas industry, and comparisons of the service life and net salvage estimates from Concentric's studies of other gas utilities. The use of survivor curves, to reflect the expected dispersion of retirement, provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data and the probable future. The forecasting of a probable future included management and operational staff interviews. The combination of the historical experience and the probable future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in Table 1 of this study (Section 5). The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

The estimates of net salvage for the mass property accounts were based in part on historical data related to actual retirement activity for the years 1983 through 2021, for most accounts. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. The estimates for net salvage for the gas plant were based on a current cost estimate of the required costs of retirement of the assets, which was inflated to the estimated end of life date of each asset group. Percentages of the cost of plant retired were calculated for each component of net salvage on an annual, three-year, five-year, and on a cumulative moving average basis.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

ACCOUNT 456 – UNDERGROUND STORAGE – COMPRESSOR EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$682,328,757	3.15%	Union: 35-R2.5 EGD: 40-R2	40-R4	Union: -5% EGD: -6%	-6%

The investment in this account relates to compressor stations located at the underground storage facilities on both the EGD and Union system. The units at the Dawn storage site are integrated with the transmission operation and include three Solar turbine compressors and seven RB 211 turbine compressors of varying horsepower. The Tecumseh site consists of eleven slow-speed reciprocating integral compressors. There are also a total of seventeen reciprocating and turbine compressor units at thirteen remote storage facilities. These units are used exclusively for moving gas into and out of storage.

The investment in Underground Storage – Compressor Equipment is approximately $682 million, representing 3.15 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1950 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2010 through 2021, of $48.6 million were recorded for this period. The currently approved life parameter for the Union account is an Iowa 35-R2.5 that produced a fit with a related residual measure of 1.4756 and an Iowa 40-R2 for the EGD account with a residual measure of 0.9048. An Iowa 40-R4 produced a related residual measure of 0.7496, as depicted on page 6-30. Discussions with EGI operational and management staff indicated that the Iowa 40-R4 is a good representation of the historical life and future expectations. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 40-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 40-R4 to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of negative five percent for Union and negative six percent for EGD. This account has shown a wide range in the historical net salvage activity since 1993. The range has been from negative 982 percent to zero percent. The three-year band has ranged from zero percent to negative 36 percent. The five-year band has ranged from zero percent to negative 22 percent. The full depth band indicates negative 16 percent. At this time, Concentric recommends that a negative ten percent net salvage estimate continue to be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative six percent for the purposes of depreciation calculations.

ACCOUNT 465 – TRANSMISSION – MAINS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$2,783,251,797	12.86%	Union: 55-R4 EGD: N/A	60-R4	Union: -15% EGD: N/A	-12%

The investments in this account typically relate to large diameter pipelines primarily used to transport natural gas from receipt points (i.e. compressor stations, custody transfer stations) to delivery locations (i.e. distribution networks or other transmission pipelines) along the pipeline. These transmission assets are part of the Transmission Integrity Management Program (TIMP) In-Line Inspection (ILI) Program or are subject to other periodic condition monitoring techniques such as external corrosion direct assessment (ECDA). These pipelines either operate at greater than 30% specified minimum yield strength (SMYS) or have been identified for inclusion in TIMP because of their criticality.

The investment in Mains is approximately $2.8 billion, representing 12.86 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1900 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2010 through 2021, of $20.5 million were recorded for this period. The currently approved life parameter for the Union account is an Iowa 55-R4 which produced a fit with a related residual measure of 4.8604. There is no EGD account for Transmission Mains. Discussions with EGI operational and management staff indicated that the Iowa 60-R4 is a good representation of the historical life and future expectations. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 60-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 60-R4 to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of negative 15 percent for Union. This account has shown a wide range in the historical net salvage activity since 2010. The range has been from negative 985 percent to negative one percent. The three-year band has ranged from negative six percent to negative 763 percent. The five-year band has ranged from negative nine percent to negative 129 percent. The full depth band indicates negative 83 percent. A review of peer Canadian gas distribution utilities indicates a range of negative 20 percent to negative 30 percent. At this time, Concentric recommends that a negative 25 percent net salvage estimate be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative 12 percent for the purposes of depreciation calculations.

ACCOUNT 466 – TRANSMISSION - COMPRESSOR EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$1,005,060,039	4.64%	Union: 30-S3 EGD: N/A	30-R4	Union: -5% EGD: N/A	-7%

The investment in this account relates to equipment within compressor stations along the transmission pipe throughout the province of Ontario. The Dawn Parkway system is composed of thirteen centrifugal compressors located approximately every 70 KM along the line. There are a total of three stations on this system: Lobo, Bright, and Parkway. In addition, there are two stations with small turbine engines on local transmission systems: Sandwich and Iroquois Falls. Operations between the Union and EGD system are as synergistic as possible with integrated operations.

The investment in Transmission – Compressor Equipment is approximately $1 billion, representing 4.64 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1900 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2010 through 2021, of $9.5 million were recorded for this period. The currently approved life parameter for the Union account is an Iowa 30-S3 that produced a fit with a related residual measure of 3.2601. EGD does not have a Transmission – Compressor Equipment account. An Iowa 30-R4 provides a better visual fit with a residual measure of 3.3601. A review of peer Canadian gas distribution utilities indicates a range of between 35 to 37 years. As such, Concentric recommends an Iowa 30-R4 to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of negative five percent for Union. This account has shown a range in the historical net salvage activity of positive 151 percent to negative 199 percent since 2010. The three-year band has ranged from negative 106 percent to positive 16 percent. The five-year band has ranged from over 15 percent to negative 125 percent. The full depth band indicates negative 28 percent. A review of a peer Canadian gas distribution utility indicates negative two percent. At this time, Concentric recommends that a negative ten percent net salvage estimate be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative seven percent for the purposes of depreciation calculations.

ACCOUNT 467 – TRANSMISSION – MEASURING AND REGULATING EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$395,646,541	1.83%	Union: 40-S1.5 EGD: N/A	40-R4	Union: -10% EGD: N/A	-15%

The investment in Transmission – Measuring and Regulating Equipment is approximately $395.6 million, representing 1.83 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1959 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2010 through 2021, of $7 million were recorded for this period. The currently approved life parameter for the Union account is an Iowa 40-S1.5 that produced a fit with a related residual measure of 0.7083. EGD did not have a Transmission – Measuring and Regulating Equipment account. An Iowa 40-R4 produced a better visual and mathematical fit with a related residual measure of 0.269, as depicted on page 6-61. Discussions with EGI operational and management staff indicated that the Iowa 40-R4 is a good representation of the historical life and future expectations. A review of peer Canadian gas distribution utilities indicates a range of between 35 to 50 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 40-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 40-R4 to represent the future expectations for the investment in this account.

This account has a currently approved net salvage of negative 10 percent for Union. This account has ranged from a high of negative three percent to a low of over negative 7,000 percent. The 3-year moving average band ranges from negative four percent to over negative 2,000 percent. The 5-year percent moving average shows a range from negative seven percent to negative 413 percent. The cumulative band indicates negative 47 percent. A review of peer Canadian gas distribution utilities indicate a range of negative seven percent to negative 75 percent. At this time, Concentric recommends that a negative 25 percent net salvage estimate be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative 15 percent for the purposes of depreciation calculations.

ACCOUNT 472.00 – STRUCTURES AND IMPROVEMENTS - OTHER

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$220,832,605	1.02%	Union: 40-R0.5 EGD: 60-S1.5	40-S0.5	Union: N/A EGD: 20%	0%

The investment in Distribution Structures and Improvements - Other is approximately $220.8 million, representing 1.02 percent of the total depreciable plant studied. For the purposes of calculating the depreciation rate the buildings within this account have been separated out by location. Disposition of these assets is based on physical condition to determine the life cycle of the building and functional assessment. The interior components (carpets, walls, etc.) are anticipated to live approximately 15 years, indicating the expectation of significant interim retirements associated with this account.

The retirements, additions and other plant transactions for the period 1928 through 2021 were analyzed by the retirement rate method. Retirements of $125.5 million were recorded for the period 1948 through 2021, resulting in actual observed data points as depicted on page 6-67. The currently approved life parameter for the Union account is an Iowa 40-R0.5 with a fit to the observed data points producing a residual measure of 0.7450 and an Iowa 60-S1.5 for the EGD account with a residual measure of 1.5815. An Iowa 40-S0.5 produces a residual measure of 0.3706. Discussions with EGI's operational and management staff indicated that the historical fit of an Iowa 40-S0.5 is a reasonable for the equipment in this account. The Iowa 40-S0.5 is within a Canadian peer comparison where the average service life ranges from 30 to 60 years. Based on the above and on Concentric's experience, Concentric recommends the use of an Iowa 40-S0.5 to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of 20 percent for EGD and no currently approved salvage for Union. The range in the historical net salvage activity for this account has been from positive 5,389 percent to negative 288 percent. The three-year band has ranged from positive 525 percent to negative 149 percent. The five-year band has ranged from positive 76 percent to negative 50 percent. The full depth band indicates negative six percent. A review of peer Canadian gas distribution utilities indicate a range of negative 10 percent to negative 65 percent. At this time, Concentric recommends that a zero percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 473.01 – SERVICES - METAL

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$549,648,294	2.54%	Union: 50-R1.5 EGD: 45-L1.5	45-S1	Union: -60% EGD: -22%	-32%

The investments in this account relate to steel pipelines that convey gas from distribution mains to end use customers.

The investment in Services – Metal is approximately $549.6 million, representing 2.54 percent of the total depreciable plant studied. The retirements, additions and other plant transactions for the period 1884 through 2021 were analyzed by the retirement rate method. Retirements of $413 million were recorded for the period 1956 through 2021, resulting in actual observed data points as depicted on page 6-71. The currently approved life parameter for the Union account is an Iowa 50-R1.5 with a residual measure of 1.5494 and an Iowa 45-L1.5 for the EGD account with a residual measure of 1.1077. An Iowa 45-S1 has a residual measure of 1.4412, as depicted on page 6-71. Discussions with EGI's operational and management staff indicated that the historical fit of the Iowa 45-S1 is a reasonable expectation for this account. Based on the above, Concentric recommends the Iowa 45-S1 to represent the future expectations for the investment in this account.

This account currently has an approved net negative salvage of negative 60 percent for Union and negative 22 percent for EGD. This account has shown a wide range trend in the historical net salvage activity since 1983. The range has been from negative 543 percent to over positive 7,000 percent. The three-year band ranges from negative 23 percent to negative 679 percent. The five-year band has ranged from negative 25 percent to negative 433 percent. The cumulative band indicates negative 69 percent. A Canadian peer comparison of approved net salvage values indicates a range from negative 60 percent to negative 125 percent. At this time, Concentric recommends that a negative 50 percent net salvage estimate be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative 32 percent for the purposes of depreciation calculations.

ACCOUNT 473.02 – SERVICES – PLASTIC

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$4,458,883,264	20.60%	Union: 55-R3 EGD: 45-L1.5	55-S3	Union: -40% EGD: -22%	-26%

The investments in this account relate to plastic pipelines that convey gas from distribution mains to end use customers.

The investment in Services – Plastic is approximately $4.5 billion, representing 20.6 percent of the total depreciable plant studied. The retirements, additions and other plant transactions for the period 1900 through 2021 were analyzed by the retirement rate method. Retirements of $96.7 million were recorded for the period 2010 through 2021, resulting in actual observed data points as depicted on page 6-77. The currently approved life parameter for the Union account is an Iowa 55-R3 with a residual measure of 6.5920 and an Iowa 45-L1.5 for the EGD account with a residual measure of 2.7074. The Iowa 55-S3 is a better fit to the historical data with a related residual measure of 2.0823. The Iowa 55-S3 is within the range of the Canadian peer comparison where the average service life ranges from 47-57 years. Based on the above, Concentric recommends the Iowa 55-S3 to represent the future expectations for the investment in this account.

This account currently has an approved net negative salvage of negative 40 percent for Union and negative 22 percent for EGD. This account has shown a wide range trend in the historical net salvage activity since 2010. The range has been from over negative 1,000 percent to over positive 1,000 percent. The three-year band ranges from negative 51 percent to over negative 1,300 percent. The five-year band has ranged from negative 49 percent to over negative 1,100 percent. The cumulative band indicates negative 168 percent. A Canadian peer comparison of approved net salvage values indicates a range from negative 60 percent to negative 125 percent. At this time, Concentric recommends that a negative 50 percent net salvage estimate be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative 26 percent for the purposes of depreciation calculations.

ACCOUNT 474.00 – REGULATORS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$488,870,931	2.25%	Union: 20-SQ EGD: N/A	25-SQ	Union: 0% EGD: N/A	0%

The investment in Regulators is approximately $488.9 million, representing 2.25 percent of the total depreciable plant studied. The currently approved life parameter for the Union account is 20-SQ. The investment in this account is more heavily weighted towards the historic Union assets, meaning that any increase in life needs to be measured against the currently approved Union life parameter. The assets in this account are expected to have a life of up to 30 to 35 years and as such a moderated increase to 25 years is recommended at this time. This moderated increase gives appropriate consideration to the increased amount of legacy Union assets. It is recommended that this account be examined closely in future depreciation studies to ensure further life extension at that time. Based on the above, Concentric recommends the Iowa 25-SQ to represent the future expectations for the investment in this account.

The Union account does not have a currently approved net salvage percentage. The assets in this account are not expected to have a cost of removal, and as such, Concentric recommends that a net salvage percentage of zero is an appropriate net salvage value.

ACCOUNT 475.21 – MAINS – COATED & WRAPPED

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$3,320,418,328	15.34%	Union: 55-R4 EGD: 61-R3	55-R3	Union: -60% EGD: -51%	-42%

The investments in this account relate to steel pipelines that convey gas to individual services or other distribution mains. These pipelines operate lower than 30% SMYS and are typically installed at pipeline pressures greater than 550 kilopascal (kPa).

The investment in Distribution Mains – Coated & Wrapped is approximately $3.3 billion, representing 15.34 percent of the total depreciable plant studied. The retirements, additions and other plant transactions for the period 1894 through 2021 were analyzed by the retirement rate method. Retirements of $208.9 million were recorded for the period 1957 through 2021, resulting in actual observed data points as depicted on page 6-83. The currently approved life parameter for the Union account is an Iowa 55-R4 with a residual measure of 1.4278 and an Iowa 61-R3 for the EGD account with a residual measure of 0.5834. The Iowa 55-R3 provides a superior visual fit through the age of 40.5 years and provides a residual measure of 1.0812. Discussions with EGI's operational and management staff indicated that the historical fit of Iowa 55-R3 is a reasonable expectation for the assets in this account. The Iowa 55-R3 is within the span of peer Canadian pipeline utilities that ranges from 55–80 years. Based on the above, Concentric recommends the Iowa 55-R3 to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of negative 60 percent for Union and negative 51 percent for EGD. This account has shown a wide range in the historical net salvage activity since 2010. The range has been from negative 21 percent to negative 336 percent. The three-year band has ranged from negative 33 percent to negative 174 percent. The five-year band has ranged from negative 34 percent to negative 53 percent. The full depth band indicates negative 80 percent. A Canadian peer comparison of approved net salvage values indicates a range from negative 25 percent to negative 90 percent. At this time, Concentric recommends that a negative 80 percent net salvage estimate be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative 42 percent for the purposes of depreciation calculations.

ACCOUNT 475.30 – MAINS – PLASTIC

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$3,480,106,028	16.08%	Union: 60-L2 EGD: 65-R3	60-R4	Union: -40% EGD: -38%	-38%

The investment in Distribution Mains – Plastic is approximately $3.5 billion, representing 16.08 percent of the total depreciable plant studied. The assets in this account relate to plastic pipelines that convey gas to individual services or other distribution mains. These pipelines operate lower than 30% SMYS and are typically installed at pipeline pressures of 550 kPa or less.

The retirements, additions and other plant transactions for the period 1958 through 2021 were analyzed by the retirement rate method. Retirements of $179.6 million were recorded for the period 1971 through 2021, resulting in actual observed data points as depicted on page 6-87. The currently approved life parameter for the Union account is an Iowa 60-L2 with a residual measure of 1.7968 and an Iowa 65-R3 for the EGD account with a residual measure of 0.3571. The Iowa 60-R4 was considered against the observed data after harmonization with a residual measure of 0.5515. The Iowa 60-R4 is within a Canadian peer comparison where the average service life ranges from 60-80 years. Based on the above, Concentric recommends the Iowa 60-R4 to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of negative 40 percent for Union and negative 38 percent for EGD. This account has shown a range of net salvage since 2010 of negative five percent to negative 703 percent. The three-year band has ranged from negative 12 percent to negative 334 percent. The five-year band has ranged from negative 12 percent to negative 252 percent. The full depth band indicates negative 23 percent. A Canadian peer comparison of approved net salvage values indicates a range of negative 25 to negative 90 percent. At this time, Concentric recommends that a negative 80 percent net salvage estimate be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative 38 percent for the purposes of depreciation calculations.

ACCOUNT 477 – DISTRIBUTION – MEASURING AND REGULATING EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$950,956,098	4.39%	Union: 40-L1 EGD: 33-L1.5	40-R2	Union: -50% EGD: -3%	-9%

The investment in Distribution – Measuring and Regulating Equipment is approximately $951 million, representing 4.39 percent of the total depreciable plant studied. There are two major categories of stations – system and customer. System stations regulate pressure from one EGI network to another, or from a transmission system owned or not by EGI to an EGI distribution network, and directly serve gas to the downstream system. Customer stations regulate pressure from the EGI network to the required delivery pressure of a customer premises.

The retirements, additions and other plant transactions for the period 1949 through 2021 were analyzed by the retirement rate method. Retirements for the period 1956 through 2021, of $79.2 million were recorded for this period resulting in actual observed data points as depicted on page 6-94. The currently approved life parameter for the Union account is an Iowa 40-L1 with a residual measure of 1.0965 and an Iowa 33-L1.5 for the EGD account with a residual measure of 1.6799. An Iowa 40-R2 was fit to the historical data and resulted in a superior residual measure of 0.6791. Based on the above, Concentric recommends the Iowa 40-R2 to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of negative 50 percent for Union and negative three percent for EGD. The historical net salvage range since 1983 has been from over negative 1,375 percent to positive 21 percent. The three-year band has ranged from negative 117 percent to positive 13 percent. The five-year band has ranged from negative 75 percent to positive nine percent. The full depth band indicates negative 25 percent. At this time, Concentric recommends that a negative 15 percent net salvage estimate be used to form the basis of the CDNS calculations for this account. When the CDNS method is used, the net salvage rate is adjusted to negative nine percent for the purposes of depreciation calculations.

ACCOUNT 478 - METERS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	CDNS Recommended Salvage
$1,020,910,894	4.72%	Union: 25-L1.5 EGD: 15-S2.5	15-S2.5	Union: N/A EGD: +5%	0%

The investment in Distribution - Meters is approximately $1 billion, representing 4.72 percent of the total depreciable plant studied. The assets in this account are meter sets, including regulator. There are several thousand inside meters within the Union system. There have been program retirements to remove these on the EGD side, however, there are still a few left.

EGI is currently investigating an advanced metering infrastructure (AMI) program. This potential program may replace the meter (and require the installation of associated network infrastructure) or may just replace the encoder receiver transmitters (ERT). Any metering program needs to consider future strategies as meters may need to be able to handle any potential hydrogen injection.

The retirements, additions and other plant transactions for the period 1884 through 2021 were analyzed by the retirement rate method. Retirements, for the period 1955 through 2021, of $400.8 million were recorded for this period. The currently approved EGD life parameter for this account is an Iowa 15-S2.5 with a residual measure of 2.6831. The currently approved Union life parameter for this account is an Iowa 25-L1.5 with a residual measure of 0.9117 An Iowa 15-S2.5 provides a residual measure of 2.3265. Discussions with EGI's operational and management staff indicated that the historical indications of an Iowa 15-S2.5 is a reasonable representation of their expectations. The Iowa 15-S2.5 is within a Canadian peer comparison where the average service life ranges from 15 to 26 years. Based on the above and on Concentric's experience, continued use of the Iowa 15-S2.5 is recommended to represent the future expectations for the investment in this account.

This account currently has an approved net salvage for the EGD account of positive 5 percent. The Union account does not have a currently approved net salvage percentage. This account has shown a range starting from negative eight percent to over 1,000 percent. The three-year band has shown a range from negative one percent to positive 10 percent. The five-year band has shown a range from negative one percent to positive nine percent. The full depth cumulative band value indicates positive two percent. A Canadian peer comparison of approved net salvage values indicates a range from zero percent to positive 10 percent. Considering the above indications, Concentric recommends that a net salvage percentage of zero is an appropriate net salvage value.

4 CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

4.1 Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because, usually all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures: Average Life Group (“ALG”) and Equal Life Group (“ELG”).

In the ELG procedure, the property group is subdivided according to service life. That is, each ELG includes that portion of the property which experiences the life of that specific group. The relative size of each ELG is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each ELG.

The table on the following page presents an illustration of the calculation of ELG depreciation in a mass property account using the Iowa 13-R2 survivor curve, zero percent net salvage and a December 31, 2015 calculation date. Each ELG, in the table, is defined by the age interval shown in columns 1 and 2. These are the ages at which the first and last retirement of each group occurs, and the group's equal life, shown in column 3, is the midpoint of the interval. For purposes of the calculation, each vintage is divided into ELGs arranged so that the midpoint of each one-year age interval coincides with the calculation date, e.g., in this case December 31. This enables the calculation of annual accruals for a twelve-month period centered on the date of calculation.

The retirement during the age interval, shown in column 4, is the size of each ELG derived from the Iowa 13-R2 survivor curve and zero percent net salvage. It is the difference between the percentage surviving at the beginning and end of the age interval. Each ELG's annual accrual, shown in column 5, equals the group's size (column 4) divided by its life (column 3), except in the circumstance of age 0.5 due to the use of the mid-year convention.

Columns 7 through 10, show the derivation of the annual and accrued factors for each vintage based on the information developed in the first five columns. The year installed is shown in column 6. For all vintages other than 2015, the summation of annual accruals for each year installed, shown in column 7, is calculated by adding one-half of the group annual accrual (column 5) for that vintage's current age interval plus the group annual accruals for all succeeding age intervals. For example, the figure 9.36279122771 for 2014, equals one-half of 0.69931333333 plus all of the succeeding figures in column 5. Only one-half of the annual accrual for the vintage's current age interval group is included in the summation because the ELG for that interval has reached the year during which it is expected to be retired.

DETAILED COMPUTATION OF ANNUAL AND ACCRUED FACTORS USING THE EQUAL LIFE GROUP PROCEDURE
INPUT PARAMETERS: CALCULATION DATE = 12-31-2015 SURVIVOR CURVE = 13-R2

Age Interval Beg.	End	Life	Retirements During Interval	Group Annual Accrual	Year Inst.	Summation of Annual Accruals	Average Percent Surviving	Annual Factor	Accrued Factor
(1)	(2)	(3)	(4)	(5)=(4)/(3)	(6)	(7)	(8)	(9)	(10)
0.000	1.000	0.500	0.81843	0.81843000000	2015	10.53087789438	99.607343	0.1057	0.0529
1.000	2.000	1.500	1.04897	0.69931333333	2014	9.36279122771	98.657081	0.0949	0.1424
2.000	3.000	2.500	1.32665	0.53066000000	2013	8.74780456105	97.469276	0.0897	0.2243
3.000	4.000	3.500	1.65967	0.47419142857	2012	8.24537884676	95.976118	0.0859	0.3007
4.000	5.000	4.500	2.05317	0.45626000000	2011	7.78015313248	94.119697	0.0827	0.3722
5.000	6.000	5.500	2.51363	0.45702363636	2010	7.32351131430	91.836296	0.0797	0.4384
6.000	7.000	6.500	3.05106	0.46939384615	2009	6.86030257304	89.053950	0.0770	0.5005
7.000	8.000	7.500	3.66989	0.48931866667	2008	6.38094631663	85.693474	0.0745	0.5588
8.000	9.000	8.500	4.36997	0.51411411765	2007	5.87922992447	81.673542	0.0720	0.6120
9.000	10.000	9.500	5.14410	0.54148421053	2006	5.35143076038	76.916510	0.0696	0.6612
10.000	11.000	10.500	5.97129	0.56869428571	2005	4.79634151226	71.358816	0.0672	0.7056
11.000	12.000	11.500	6.79860	0.59118260870	2004	4.21640306506	64.973866	0.0649	0.7464
12.000	13.000	12.500	7.54947	0.60395760000	2003	3.61883296071	57.799833	0.0626	0.7825
13.000	14.000	13.500	8.12298	0.60170222222	2002	3.01600304960	49.963612	0.0604	0.8154
14.000	15.000	14.500	8.39246	0.57879034483	2001	2.42575676607	41.705891	0.0582	0.8439
15.000	16.000	15.500	8.25458	0.53255354839	2000	1.87008481946	33.382372	0.0560	0.8680
16.000	17.000	16.500	7.66186	0.46435515152	1999	1.37163046951	25.424151	0.0539	0.8894
17.000	18.000	17.500	6.66225	0.38070000000	1998	0.94910289375	18.262094	0.0520	0.9100
18.000	19.000	18.500	5.40212	0.29200648649	1997	0.61274965050	12.229909	0.0501	0.9269
19.000	20.000	19.500	4.06774	0.20860205128	1996	0.36244538162	7.494980	0.0484	0.9438
20.000	21.000	20.500	2.81382	0.13725951220	1995	0.18951459988	4.054203	0.0467	0.9574
21.000	22.000	21.500	1.70757	0.07942186047	1994	0.08117391354	1.793508	0.0453	0.9740
22.000	23.000	22.500	0.78015	0.03467333333	1993	0.02412631664	0.549647	0.0439	0.9878
23.000	24.000	23.500	0.15903	0.00676723404	1992	0.00340603296	0.080054	0.0425	0.9988
24.000	24.180	24.090	0.00054	0.00002241594	1991	0.00000201743	0.000049	0.0412	1.0000
		TOTAL	100.00000						

The summation of annual accruals (column 7) for installations during 2015 is calculated on the basis of an in-service date at the midpoint of the year, i.e., June 30. In as much as the overall calculation is centered on December 31, 2015, the first figure in column 7, for vintage 2015, equals all of the group annual accrual for the first ELG plus the accruals for all of the subsequent ELGs.

The average percent surviving derived from the Iowa 13-R2 survivor curve and zero percent net salvage, is shown in column 8 for each age interval. The annual factor, shown in column 9, is the result of dividing the summation of annual accruals (column 7) by the average percent surviving (column 8). The accrued factor, shown in column 10, equals the annual factor multiplied by the age of the group at December 31, 2015.

4.2 Calculation of Annual and Accrued Amortization

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable natural gas plant in service. The accounts and their amortization periods are as follows:

Account	Title	Investment	Recommended Amortization Period in Years
474.00	Regulators	$488,870,931	25
475.00	Mains Envision	$181,264,676	25
483.00	Office Furniture and Equipment	$29,776,062	15
486.00	Tools and Work Equipment	$79,966,854	15
487.70	Rental - NGV Appl	$864,755	15
487.80	Rental – NGV Stations	$7,774,175	20
488.00	Communication Structures and Equipment	$11,224,609	10
490.00	Computer Equipment	$30,306,679	4
490.30	Computer Equipment – WAMS	$4,680,899	10
491.01	Software Acquired Intangibles	$155,164,785	4
491.02	Software Developed Intangibles	$38,776,288	4
491.03	CIS Acquired Software	$87,626,214	10
491.04	WAMS	$85,221,905	10

For the purpose of calculating annual amortization amounts, as of December 31, 2021, the book depreciation reserve for each plant account (or sub-account) is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

4.3 Monitoring of Book Accumulated Depreciation

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period equal to the composite remaining life for each property group where the variance exceeds five percent of the calculated accrued depreciation.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual remaining lives in accordance with the following equation:

$$Composite\ Remaining\ Life = \frac{\sum(\frac{Book\ Cost}{Life}\ x\ Remaining\ Life)}{\sum\frac{Book\ Cost}{Life}} \qquad (1)$$

The book costs and lives of the several vintages, which are summed in the foregoing equation, are defined by the estimated future survivor curve. In as much as book cost divided by life equals the Whole Life annual accrual, the foregoing equation reduces to the following form:

$$Composite\ Remaining\ Life = \frac{\sum Whole\ Life\ Future\ Accruals}{\sum Whole\ Life\ Annual\ Accrual} \qquad (2)$$

or

$$Composite\ Remaining\ Life = \frac{\sum \quad BookCost - Calc, Reserve}{\sum Whole\ Life\ Annual\ Accrual} \qquad (3)$$

SECTION 5

5 RESULTS OF THE STUDY

5.1 Qualification of Results

The calculated annual and accrued depreciation are the principal results of the study and are shown in Table 1, related to investment as of December 31, 2021. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the Straight-Line method, using the ELG procedure, based on estimates which reflect considerations of current historical evidence and expected future conditions.

5.2 Description of Detailed Tabulations

The following tables provides summaries by account of the original cost of investment, calculated and booked accumulated depreciation amounts, the required amount of annual depreciation expense, the required depreciation rate to be applied against the original cost of the account and the estimated composite remaining life of the surviving plant in service.

The detailed calculations of annual depreciation applicable to depreciable assets, as of December 31, 2021, are presented in account sequence starting in Section 5 – Page 5-2. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth (for each installation year) the original cost, calculated accrued depreciation and the calculated annual accrual.

ENBRIDGE GAS INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account (1)	Description (2)	Truncation Date (3)	Estimated Survivor Curve (4)	Net Salvage Percent (5)	Surviving Original Cost as of 12/31/2021 (6)	Book Reserve (7)	Future Accruals (8)	Annual Accrual Amount (9)	Composite Remaining Life (10)	Annual Accrual Rate (11)
LOCAL STORAGE PLANT										
442.00	STRUCTURES AND IMPROVEMENTS	0	40-S5	0%	6,282,181	2,805,060	3,477,121	105,928	24.7	1.69%
443.01	HOLDER - STORAGE TANK	0	45-R4	0%	5,804,412	4,023,544	1,780,869	55,594	19.1	0.96%
443.02	HOLDER EQUIPMENT	0	55-R4	0%	21,554,522	11,363,396	10,191,126	229,183	36.8	1.06%
TOTAL LOCAL STORAGE PLANT					**33,641,115**	**18,192,000**	**15,449,115**	**390,705**		1.16%
UNDERGROUND STORAGE PLANT										
451.00	LAND RIGHTS INTANGIBLE	0	55-R4	0%	74,762,354	45,841,825	28,920,529	1,102,904	23.0	1.48%
452.00	STRUCTURES AND IMPROVEMENTS	0	40-R3	-10%	104,433,820	47,148,032	67,729,170	4,114,129	19.8	3.94%
453.00	WELLS	0	45-R2.5	-30%	143,144,395	50,040,540	136,047,173	5,515,551	25.9	3.85%
454.00	WELL EQUIPMENT	0	40-R2	0%	13,364,517	8,575,936	4,788,581	175,831	21.4	1.32%
455.00	FIELD LINES	0	55-R3	-8%	201,920,080	53,298,115	164,775,572	5,130,627	33.4	2.54%
456.00	COMPRESSOR EQUIPMENT	0	40-R4	-6%	682,328,757	228,311,196	494,957,286	19,661,453	25.5	2.88%
457.00	REGULATING AND MEASURING EQUIPMENT	0	35-R3	-14%	77,194,133	51,829,828	36,171,484	2,003,634	15.6	2.60%
TOTAL UNDERGROUND STORAGE PLANT					**1,297,148,055**	**485,045,470**	**933,389,796**	**37,704,129**		2.91%
TRANSMISSION PLANT										
461.00	LAND RIGHTS INTANGIBLE	0	60-R4	0%	88,171,402	20,599,533	67,571,869	1,507,598	44.3	1.71%
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	0	50-S4	-5%	163,351,958	40,353,631	131,165,925	3,377,914	37.7	2.07%
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	0	55-S4	-6%	11,252,284	7,167,268	4,760,153	157,646	26.2	1.40%
464.00	EQUIPMENT	0	50-S4	-5%	2,920,218	523,642	2,542,587	65,185	39.7	2.23%
465.00	MAINS	0	60-R4	-12%	2,783,251,797	919,330,147	2,197,911,866	49,201,674	42.3	1.77%
466.00	COMPRESSOR EQUIPMENT	0	30-R4	-7%	1,005,060,039	331,530,582	743,883,660	37,417,456	19.6	3.72%
467.00	MEASURING AND REGULATING EQUIPMENT	0	40-R4	-15%	395,646,542	119,798,512	335,195,011	12,112,032	27.7	3.06%
TOTAL TRANSMISSION PLANT					**4,449,654,239**	**1,439,303,314**	**3,483,031,070**	**103,839,505**		2.33%
DISTRIBUTION PLANT										
471.00	LAND RIGHTS INTANGIBLE	0	60-R4	0%	63,907,560	12,099,619	51,807,941	1,150,753	45.2	1.80%
472.00 *	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-S0.5	0%	220,832,605	64,014,227	156,818,378	7,005,487	21.7	3.17%
472.31	STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	5,056,171	24,605,944	1,325,428	18.6	4.47%
472.32	STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	5,549,955	17,666,591	991,735	17.9	4.27%
472.33	STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	9,778,917	10,010,985	2,365,393	4.2	11.95%
472.34	STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	4,069,504	12,668,072	704,663	18.0	4.21%
472.35	STRUCTURES AND IMPROVEMENTS - MAINWAY	2023	40-S0.5	0%	15,937,297	3,958,252	11,979,045	8,045,939	1.5	50.48%
473.01	SERVICES - METAL	0	45-S1	-32%	549,648,294	268,325,815	457,209,934	19,924,844	23.0	3.63%
473.02	SERVICES - PLASTIC	0	55-S3	-26%	4,458,883,265	1,384,833,504	4,233,359,410	121,567,634	35.7	2.73%
474.00	REGULATORS	0	25-SQ	0%	488,870,931	59,858,893	429,012,038	43,329,780	15.5	8.86%
475.00	MAINS - ENVISION	0	25-SQ	0%	181,264,676	59,887,548	121,377,128	10,469,399	12.2	5.78%
475.21	MAINS - COATED & WRAPPED	0	55-R3	-42%	3,320,418,328	1,051,359,036	3,663,634,991	112,249,761	34.9	3.38%
475.30	MAINS - PLASTIC	0	60-R4	-38%	3,480,106,028	928,431,883	3,874,114,436	94,562,548	42.0	2.72%
476.00	COMPANY NGV COMPRESSOR STATIONS	0	17-S2.5	0%	9,878,703	5,181,735	4,696,968	365,238	9.7	3.70%
477.00	MEASURING AND REGULATING EQUIPMENT	0	40-R2	-9%	950,956,098	367,887,432	668,654,715	27,440,188	23.3	2.89%
477.01	CUSTOMER M&R EQUIPMENT	0	35-R3	0%	143,726,981	52,094,469	91,632,512	4,800,551	19.4	3.34%
478.00	METERS	0	15-S2.5	0%	1,020,910,894	469,525,898	551,384,996	104,686,373	6.4	10.25%
TOTAL DISTRIBUTION PLANT					**14,994,747,798**	**4,751,912,857**	**14,380,634,082**	**560,985,714**		3.74%
GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	0	40-R1.5	0%	13,255,572	8,677,610	4,577,962	191,336	23.2	1.44%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	19,270,729	34,192,626	3,400,629	10.0	6.36%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	6,391,978	9,286,662	9,286,663	0.5	59.23%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	6,852,980	29,818,839	1,544,848	19.3	4.21%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	11,589,939	57,968,736	3,906,954	16.4	5.62%
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	1,664,764	17,572,928	2,814,701	6.2	14.63%

ENBRIDGE GAS INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account	Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
483.00	OFFICE FURNITURE AND EQUIPMENT	0	15-SQ	0%	29,776,062	20,323,396	9,452,666	1,200,881	6.0	4.03%
484.00	TRANSPORTATION EQUIPMENT	0	12-L2.5	0%	134,722,078	89,525,829	45,196,249	6,268,747	5.7	4.65%
485.00	HEAVY WORK EQUIPMENT	0	17-L1.5	0%	44,128,921	12,811,266	31,317,655	3,658,037	8.6	8.29%
486.00	TOOLS AND WORK EQUIPMENT	0	15-SQ	0%	79,966,854	26,128,214	53,838,641	9,529,666	7.6	11.92%
487.70	RENTAL - REFUEL APPL	0	15-SQ	0%	864,755	92,164	772,591	86,895	9.3	10.05%
487.80	RENTAL - NGV STATIONS	0	20-SQ	0%	7,774,175	2,397,143	5,377,032	288,265	18.4	3.71%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	0	10-SQ	0%	11,224,609	4,990,530	6,234,079	2,946,627	2.6	26.25%
490.00	COMPUTER EQUIPMENT	0	4-SQ	0%	30,306,679	20,774,567	9,532,112	4,041,429	1.7	13.34%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
490.30	COMPUTER EQUIPMENT - WAMS	0	10-SQ	0%	4,680,899	2,418,465	2,262,435	502,763	4.5	10.74%
491.01	SOFTWARE ACQUIRED INTANGIBLES	0	4-SQ	0%	155,164,785	107,550,337	47,614,448	13,604,128	2.0	8.77%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.02	SOFTWARE DEVELOPED INTANGIBLES	0	4-SQ	0%	38,776,288	25,519,357	13,256,930	3,892,471	2.2	10.04%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.03	CIS ACQUIRED SOFTWARE	0	10-SQ	0%	87,626,214	20,250,171	67,376,042	7,217,716	8.4	8.24%
**	SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	10.00%
491.04	WAMS	0	10-SQ	0%	85,221,905	44,031,318	41,190,587	9,153,464	4.5	10.74%
TOTAL GENERAL PLANT					**918,099,975**	**431,260,756**	**486,839,219**	**83,536,220**		9.10%
TOTAL UTILITY PLANT STUDIED					**21,693,291,183**	**7,125,714,397**	**19,299,343,283**	**786,456,273**		**3.63%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
***	Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**22,014,375,825**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.
** New depreciation rate for major longer term intangible asset additions post 2023
*** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

SECTION 6

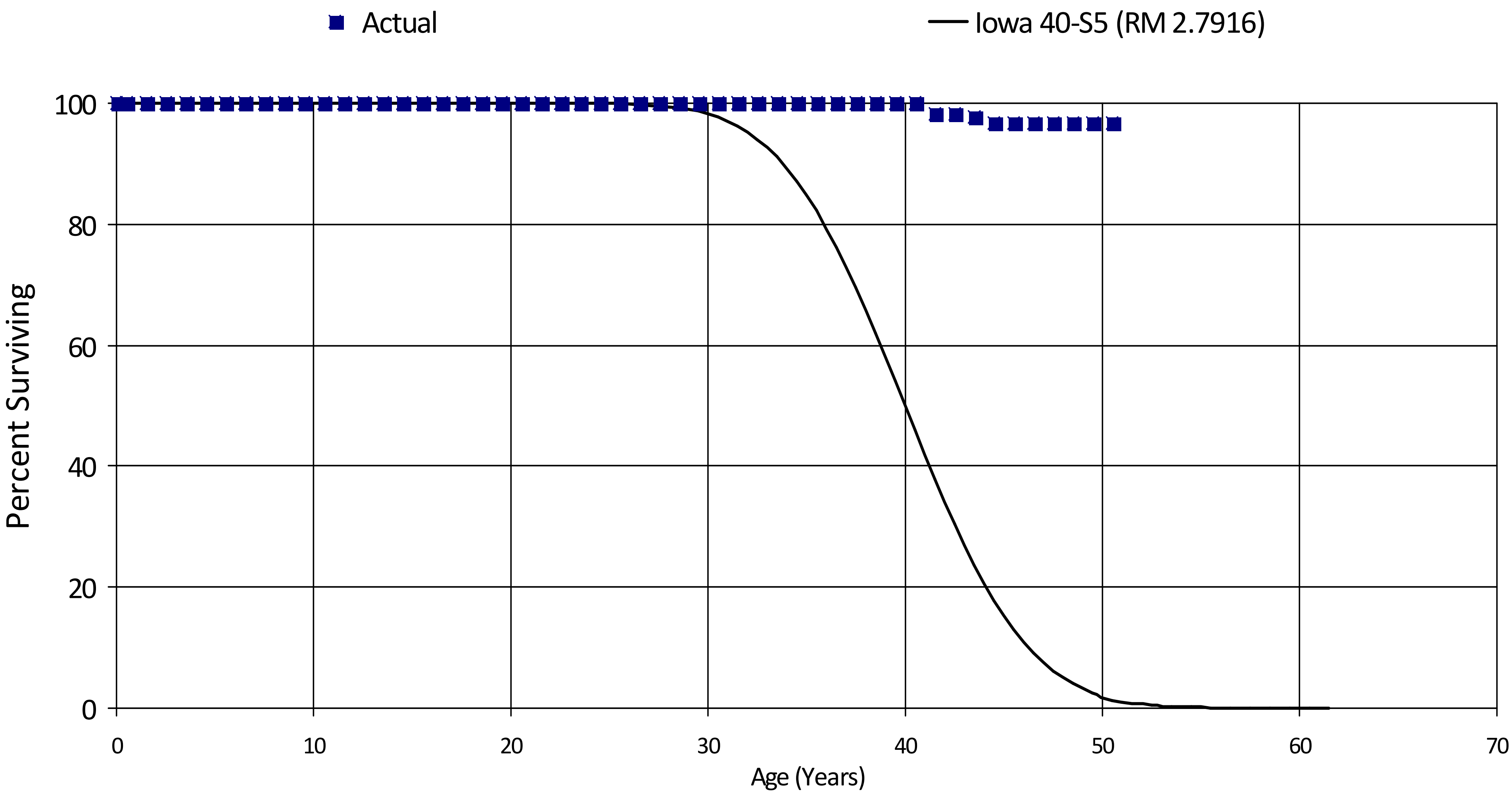
6 RETIREMENT RATE ANALYSIS

Enbridge Gas Inc.

Account 442.00 - Local Storage - Structures and Improvements

Placement Band - 1970 - 2021   Experience Band - 2011 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 442.00 - Local Storage - Structures and Improvements

Placement Band - 1970 - 2021 Experience Band - 2011 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,332,166	0	0.00000	1.00000	100.00
0.5	5,183,054	0	0.00000	1.00000	100.00
1.5	4,786,552	0	0.00000	1.00000	100.00
2.5	4,739,547	0	0.00000	1.00000	100.00
3.5	4,704,129	0	0.00000	1.00000	100.00
4.5	4,223,512	0	0.00000	1.00000	100.00
5.5	4,123,350	0	0.00000	1.00000	100.00
6.5	3,851,814	0	0.00000	1.00000	100.00
7.5	3,693,570	0	0.00000	1.00000	100.00
8.5	3,618,570	0	0.00000	1.00000	100.00
9.5	2,987,384	0	0.00000	1.00000	100.00
10.5	2,675,891	0	0.00000	1.00000	100.00
11.5	2,512,002	0	0.00000	1.00000	100.00
12.5	2,501,940	0	0.00000	1.00000	100.00
13.5	2,477,000	0	0.00000	1.00000	100.00
14.5	2,348,993	0	0.00000	1.00000	100.00
15.5	2,110,600	0	0.00000	1.00000	100.00
16.5	1,928,871	0	0.00000	1.00000	100.00
17.5	1,928,871	0	0.00000	1.00000	100.00
18.5	1,928,871	0	0.00000	1.00000	100.00
19.5	1,928,871	0	0.00000	1.00000	100.00
20.5	1,909,568	0	0.00000	1.00000	100.00
21.5	1,909,568	0	0.00000	1.00000	100.00
22.5	1,909,568	0	0.00000	1.00000	100.00
23.5	1,472,470	0	0.00000	1.00000	100.00
24.5	1,472,470	0	0.00000	1.00000	100.00
25.5	1,472,470	0	0.00000	1.00000	100.00
26.5	1,472,470	0	0.00000	1.00000	100.00

Enbridge Gas Inc.

Account 442.00 - Local Storage - Structures and Improvements

Placement Band - 1970 - 2021   Experience Band - 2011 - 2021

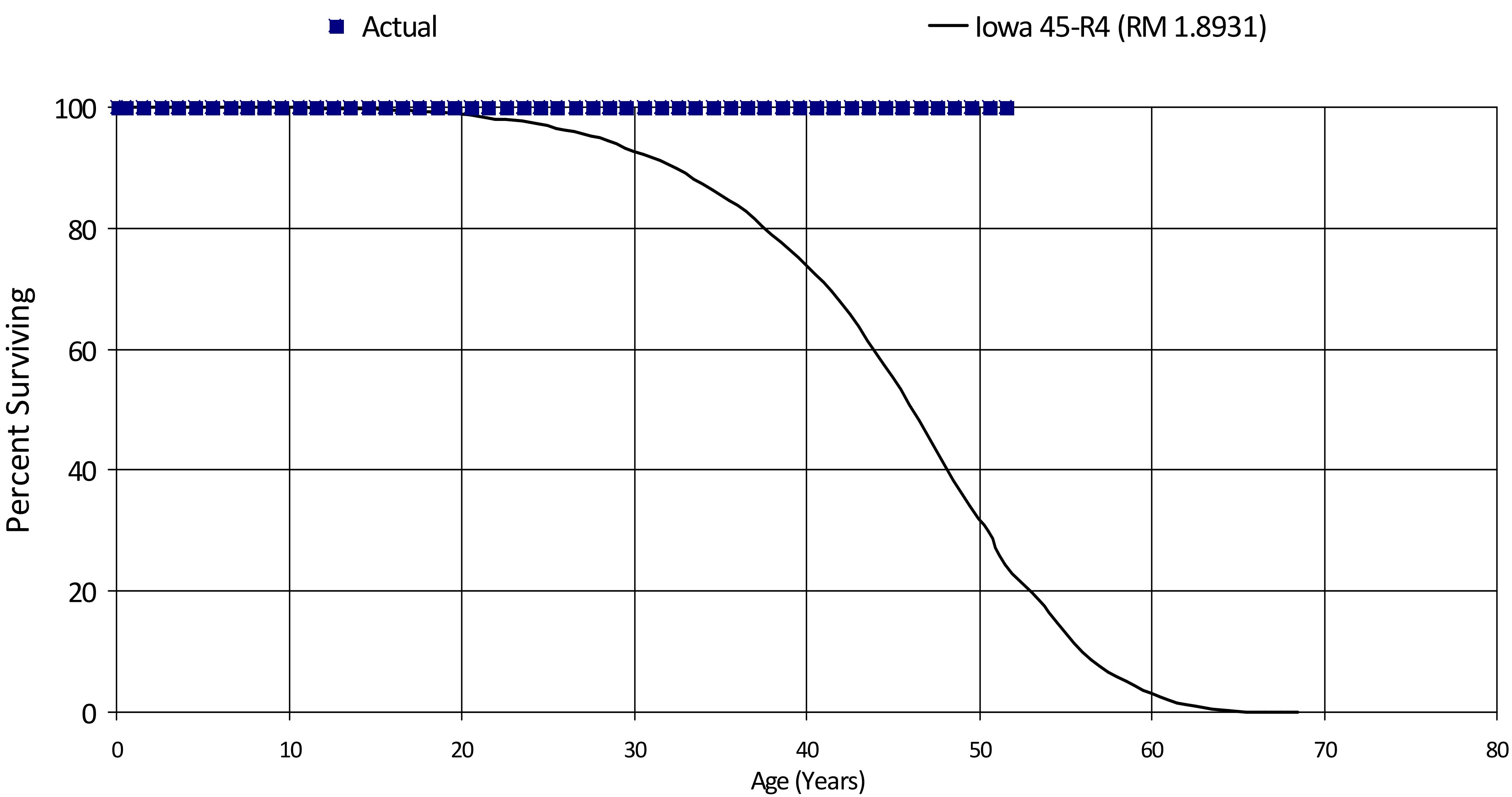
27.5	1,472,470	0	0.00000	1.00000	100.00
28.5	1,472,470	0	0.00000	1.00000	100.00
29.5	1,472,470	0	0.00000	1.00000	100.00
30.5	1,472,470	0	0.00000	1.00000	100.00
31.5	1,472,470	0	0.00000	1.00000	100.00
32.5	1,472,470	0	0.00000	1.00000	100.00
33.5	1,472,470	0	0.00000	1.00000	100.00
34.5	1,472,470	0	0.00000	1.00000	100.00
35.5	1,472,470	0	0.00000	1.00000	100.00
36.5	1,472,470	0	0.00000	1.00000	100.00
37.5	1,472,470	0	0.00000	1.00000	100.00
38.5	1,472,470	0	0.00000	1.00000	100.00
39.5	1,472,470	0	0.00000	1.00000	100.00
40.5	1,472,470	26,920	0.01828	0.98172	100.00
41.5	1,445,550	0	0.00000	1.00000	98.17
42.5	1,445,550	5,792	0.00401	0.99599	98.17
43.5	1,439,758	17,273	0.01200	0.98800	97.78
44.5	1,422,485	0	0.00000	1.00000	96.61
45.5	1,422,485	0	0.00000	1.00000	96.61
46.5	1,422,485	0	0.00000	1.00000	96.61
47.5	1,422,485	0	0.00000	1.00000	96.61
48.5	1,422,485	0	0.00000	1.00000	96.61
49.5	1,422,485	0	0.00000	1.00000	96.61
50.5	1,422,485	0	0.00000	1.00000	96.61
	Totals:	49,985			

Enbridge Gas Inc.

Account 443.01 - Local Storage - Holder Storage Tank

Placement Band - 1969 - 2021   Experience Band - 2021 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 443.01 - Local Storage - Holder Storage Tank

Placement Band - 1969 - 2021   Experience Band - 2021 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,804,412	0	0.00000	1.00000	100.00
0.5	4,608,680	0	0.00000	1.00000	100.00
1.5	4,608,680	0	0.00000	1.00000	100.00
2.5	4,608,680	0	0.00000	1.00000	100.00
3.5	4,608,680	0	0.00000	1.00000	100.00
4.5	4,598,506	0	0.00000	1.00000	100.00
5.5	4,574,078	0	0.00000	1.00000	100.00
6.5	4,574,078	0	0.00000	1.00000	100.00
7.5	4,574,078	0	0.00000	1.00000	100.00
8.5	4,574,078	0	0.00000	1.00000	100.00
9.5	4,574,078	0	0.00000	1.00000	100.00
10.5	4,574,078	0	0.00000	1.00000	100.00
11.5	4,574,078	0	0.00000	1.00000	100.00
12.5	4,574,078	0	0.00000	1.00000	100.00
13.5	4,574,078	0	0.00000	1.00000	100.00
14.5	4,574,078	0	0.00000	1.00000	100.00
15.5	4,574,078	0	0.00000	1.00000	100.00
16.5	4,574,078	0	0.00000	1.00000	100.00
17.5	4,574,078	0	0.00000	1.00000	100.00
18.5	4,574,078	0	0.00000	1.00000	100.00
19.5	4,253,187	0	0.00000	1.00000	100.00
20.5	4,253,187	0	0.00000	1.00000	100.00
21.5	4,253,187	0	0.00000	1.00000	100.00
22.5	2,186,400	0	0.00000	1.00000	100.00
23.5	2,186,400	0	0.00000	1.00000	100.00
24.5	2,186,400	0	0.00000	1.00000	100.00
25.5	2,186,400	0	0.00000	1.00000	100.00
26.5	2,186,400	0	0.00000	1.00000	100.00

Enbridge Gas Inc.

Account 443.01 - Local Storage - Holder Storage Tank

Placement Band - 1969 - 2021 Experience Band - 2021 - 2021

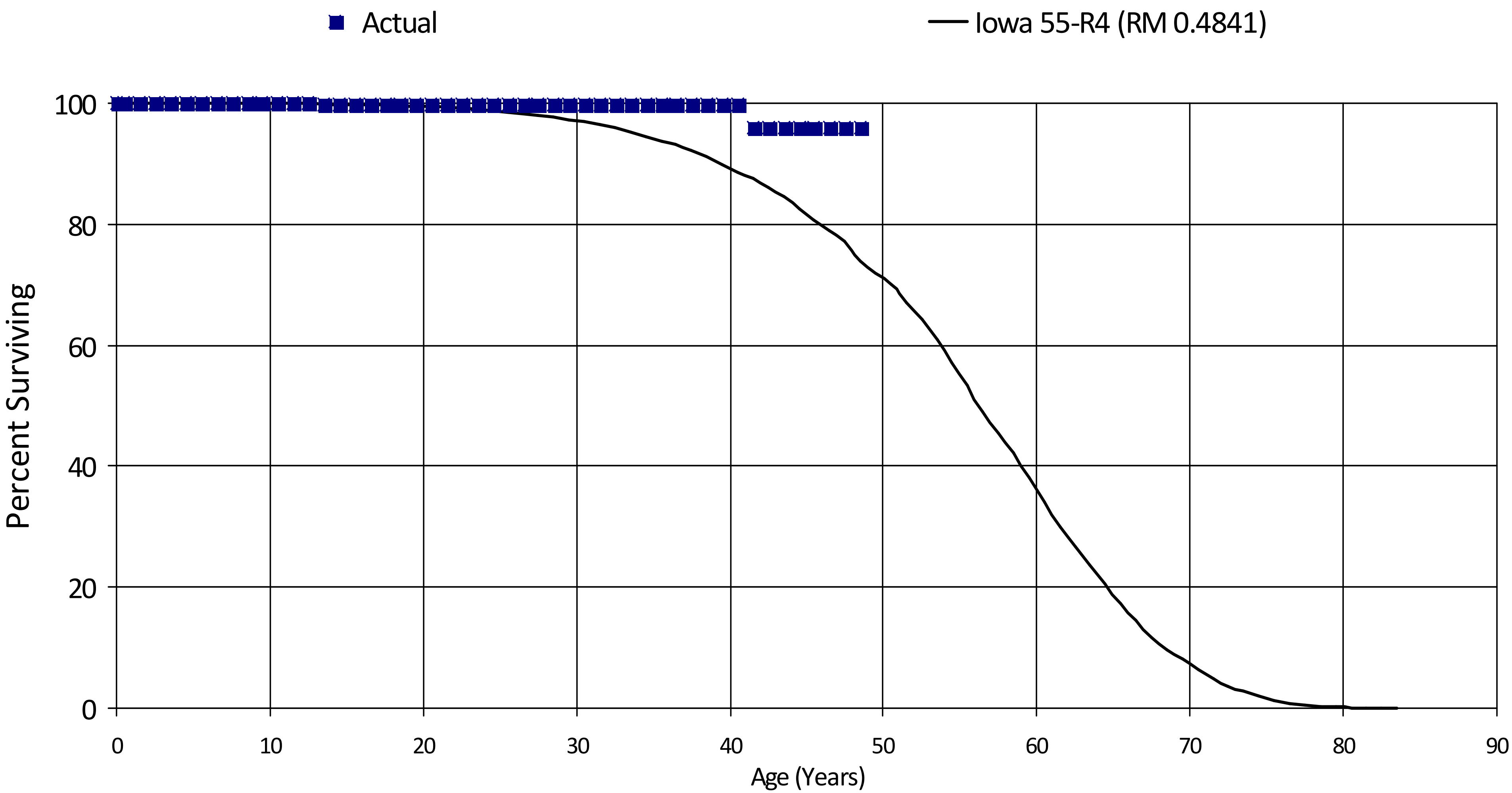
27.5	2,186,400	0	0.00000	1.00000	100.00
28.5	2,186,400	0	0.00000	1.00000	100.00
29.5	2,186,400	0	0.00000	1.00000	100.00
30.5	2,186,400	0	0.00000	1.00000	100.00
31.5	2,186,400	0	0.00000	1.00000	100.00
32.5	2,186,400	0	0.00000	1.00000	100.00
33.5	2,186,400	0	0.00000	1.00000	100.00
34.5	2,186,400	0	0.00000	1.00000	100.00
35.5	2,186,400	0	0.00000	1.00000	100.00
36.5	2,186,400	0	0.00000	1.00000	100.00
37.5	2,186,400	0	0.00000	1.00000	100.00
38.5	2,186,400	0	0.00000	1.00000	100.00
39.5	2,186,400	0	0.00000	1.00000	100.00
40.5	2,186,400	0	0.00000	1.00000	100.00
41.5	2,186,400	0	0.00000	1.00000	100.00
42.5	2,186,400	0	0.00000	1.00000	100.00
43.5	2,186,400	0	0.00000	1.00000	100.00
44.5	2,186,400	0	0.00000	1.00000	100.00
45.5	2,186,400	0	0.00000	1.00000	100.00
46.5	2,186,400	0	0.00000	1.00000	100.00
47.5	2,186,400	0	0.00000	1.00000	100.00
48.5	2,186,400	0	0.00000	1.00000	100.00
49.5	2,186,400	0	0.00000	1.00000	100.00
50.5	2,186,400	0	0.00000	1.00000	100.00
51.5	2,186,400	0	0.00000	1.00000	100.00
	Totals:	0			

Enbridge Gas Inc.

Account 443.02 - Local Storage - Holder Equipment

Placement Band - 1972 - 2021 Experience Band - 2014 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 443.02 - Local Storage - Holder Equipment

Placement Band - 1972 - 2021 Experience Band - 2014 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	21,734,877	0	0.00000	1.00000	100.00
0.5	20,387,025	0	0.00000	1.00000	100.00
1.5	20,182,324	0	0.00000	1.00000	100.00
2.5	20,182,324	0	0.00000	1.00000	100.00
3.5	19,714,033	0	0.00000	1.00000	100.00
4.5	17,801,414	0	0.00000	1.00000	100.00
5.5	16,338,636	0	0.00000	1.00000	100.00
6.5	16,305,352	0	0.00000	1.00000	100.00
7.5	14,154,837	0	0.00000	1.00000	100.00
8.5	10,116,442	0	0.00000	1.00000	100.00
9.5	9,961,380	0	0.00000	1.00000	100.00
10.5	9,869,300	0	0.00000	1.00000	100.00
11.5	8,678,146	0	0.00000	1.00000	100.00
12.5	8,658,368	28,683	0.00331	0.99669	100.00
13.5	8,629,685	0	0.00000	1.00000	99.67
14.5	8,580,059	0	0.00000	1.00000	99.67
15.5	6,405,584	0	0.00000	1.00000	99.67
16.5	6,405,584	0	0.00000	1.00000	99.67
17.5	6,360,399	0	0.00000	1.00000	99.67
18.5	6,360,399	0	0.00000	1.00000	99.67
19.5	5,638,890	0	0.00000	1.00000	99.67
20.5	4,986,846	0	0.00000	1.00000	99.67
21.5	4,855,011	0	0.00000	1.00000	99.67
22.5	3,928,921	0	0.00000	1.00000	99.67
23.5	3,928,921	0	0.00000	1.00000	99.67
24.5	3,928,921	0	0.00000	1.00000	99.67
25.5	3,928,921	0	0.00000	1.00000	99.67
26.5	3,928,921	0	0.00000	1.00000	99.67

Enbridge Gas Inc.

Account 443.02 - Local Storage - Holder Equipment

Placement Band - 1972 - 2021 Experience Band - 2014 - 2021

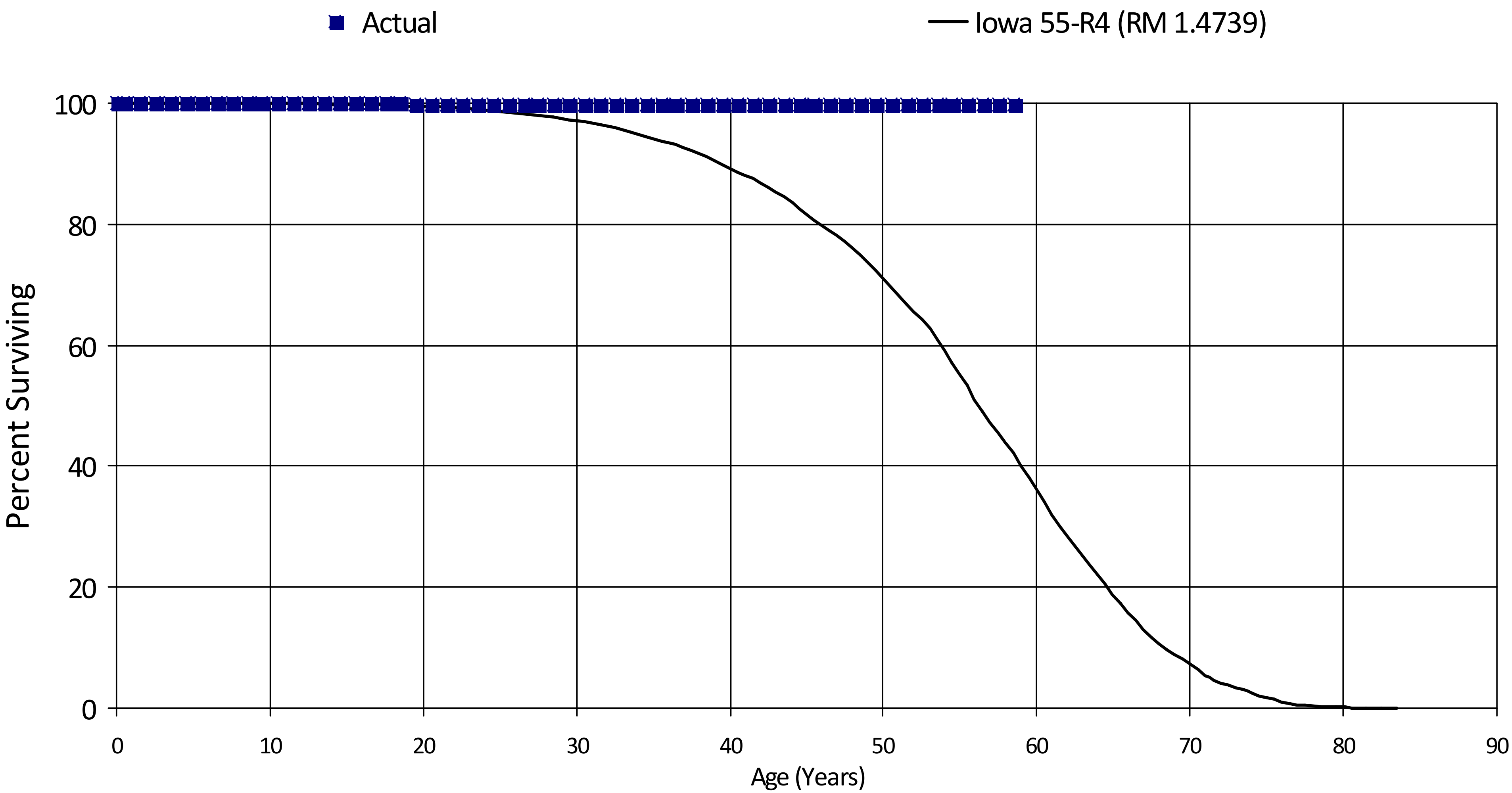
27.5	3,928,921	0	0.00000	1.00000	99.67
28.5	3,928,921	0	0.00000	1.00000	99.67
29.5	3,928,921	0	0.00000	1.00000	99.67
30.5	3,928,921	0	0.00000	1.00000	99.67
31.5	3,928,921	0	0.00000	1.00000	99.67
32.5	3,928,921	0	0.00000	1.00000	99.67
33.5	3,928,921	0	0.00000	1.00000	99.67
34.5	3,928,921	0	0.00000	1.00000	99.67
35.5	3,928,921	0	0.00000	1.00000	99.67
36.5	3,928,921	0	0.00000	1.00000	99.67
37.5	3,928,921	0	0.00000	1.00000	99.67
38.5	3,928,921	0	0.00000	1.00000	99.67
39.5	3,928,921	0	0.00000	1.00000	99.67
40.5	3,928,921	151,672	0.03860	0.96140	99.67
41.5	3,777,249	0	0.00000	1.00000	95.82
42.5	3,777,249	0	0.00000	1.00000	95.82
43.5	3,777,249	0	0.00000	1.00000	95.82
44.5	3,777,249	0	0.00000	1.00000	95.82
45.5	3,777,249	0	0.00000	1.00000	95.82
46.5	3,777,249	0	0.00000	1.00000	95.82
47.5	3,777,249	0	0.00000	1.00000	95.82
48.5	995,702	0	0.00000	1.00000	95.82
	Totals:	180,355			

Enbridge Gas Inc.

Account 451.00 - Underground Storage - Land Rights Intangible

Placement Band - 1949 - 2021 Experience Band - 2009 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 451.00 - Underground Storage - Land Rights Intangible

Placement Band - 1949 - 2021   Experience Band - 2009 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	74,908,618	20,841	0.00028	0.99972	100.00
0.5	74,887,777	0	0.00000	1.00000	99.97
1.5	74,887,777	0	0.00000	1.00000	99.97
2.5	74,887,777	0	0.00000	1.00000	99.97
3.5	74,887,777	0	0.00000	1.00000	99.97
4.5	74,887,777	0	0.00000	1.00000	99.97
5.5	74,887,777	0	0.00000	1.00000	99.97
6.5	74,813,139	0	0.00000	1.00000	99.97
7.5	74,813,139	0	0.00000	1.00000	99.97
8.5	73,863,645	0	0.00000	1.00000	99.97
9.5	73,013,268	0	0.00000	1.00000	99.97
10.5	73,013,268	0	0.00000	1.00000	99.97
11.5	73,013,268	0	0.00000	1.00000	99.97
12.5	73,013,268	2	0.00000	1.00000	99.97
13.5	73,013,265	0	0.00000	1.00000	99.97
14.5	73,012,237	11,356	0.00016	0.99984	99.97
15.5	73,000,881	0	0.00000	1.00000	99.95
16.5	73,000,881	0	0.00000	1.00000	99.95
17.5	72,868,017	0	0.00000	1.00000	99.95
18.5	72,868,017	77,356	0.00106	0.99894	99.95
19.5	71,720,969	36,709	0.00051	0.99949	99.84
20.5	65,475,369	0	0.00000	1.00000	99.79
21.5	63,604,544	0	0.00000	1.00000	99.79
22.5	56,119,134	0	0.00000	1.00000	99.79
23.5	55,896,079	0	0.00000	1.00000	99.79
24.5	52,251,495	0	0.00000	1.00000	99.79
25.5	51,922,776	0	0.00000	1.00000	99.79
26.5	50,820,868	0	0.00000	1.00000	99.79

Enbridge Gas Inc.

Account 451.00 - Underground Storage - Land Rights Intangible

Placement Band - 1949 - 2021 Experience Band - 2009 - 2021

27.5	40,142,098	0	0.00000	1.00000	99.79
28.5	40,020,871	0	0.00000	1.00000	99.79
29.5	40,011,892	0	0.00000	1.00000	99.79
30.5	39,342,833	0	0.00000	1.00000	99.79
31.5	39,342,785	0	0.00000	1.00000	99.79
32.5	30,767,282	0	0.00000	1.00000	99.79
33.5	29,480,302	0	0.00000	1.00000	99.79
34.5	13,506,904	0	0.00000	1.00000	99.79
35.5	13,506,904	0	0.00000	1.00000	99.79
36.5	13,503,764	0	0.00000	1.00000	99.79
37.5	13,503,764	0	0.00000	1.00000	99.79
38.5	13,503,764	0	0.00000	1.00000	99.79
39.5	13,503,764	0	0.00000	1.00000	99.79
40.5	13,503,764	0	0.00000	1.00000	99.79
41.5	13,494,748	0	0.00000	1.00000	99.79
42.5	13,494,748	0	0.00000	1.00000	99.79
43.5	13,494,748	0	0.00000	1.00000	99.79
44.5	7,539,750	0	0.00000	1.00000	99.79
45.5	7,539,750	0	0.00000	1.00000	99.79
46.5	7,539,750	0	0.00000	1.00000	99.79
47.5	7,539,750	0	0.00000	1.00000	99.79
48.5	7,539,750	0	0.00000	1.00000	99.79
49.5	7,539,750	0	0.00000	1.00000	99.79
50.5	7,539,750	0	0.00000	1.00000	99.79
51.5	7,539,750	0	0.00000	1.00000	99.79
52.5	7,539,750	0	0.00000	1.00000	99.79
53.5	7,539,750	0	0.00000	1.00000	99.79
54.5	7,539,750	0	0.00000	1.00000	99.79
55.5	7,539,750	0	0.00000	1.00000	99.79
56.5	7,539,750	0	0.00000	1.00000	99.79
57.5	2,261,925	0	0.00000	1.00000	99.79

Enbridge Gas Inc.

Account 451.00 - Underground Storage - Land Rights Intangible

Placement Band - 1949 - 2021   Experience Band - 2009 - 2021

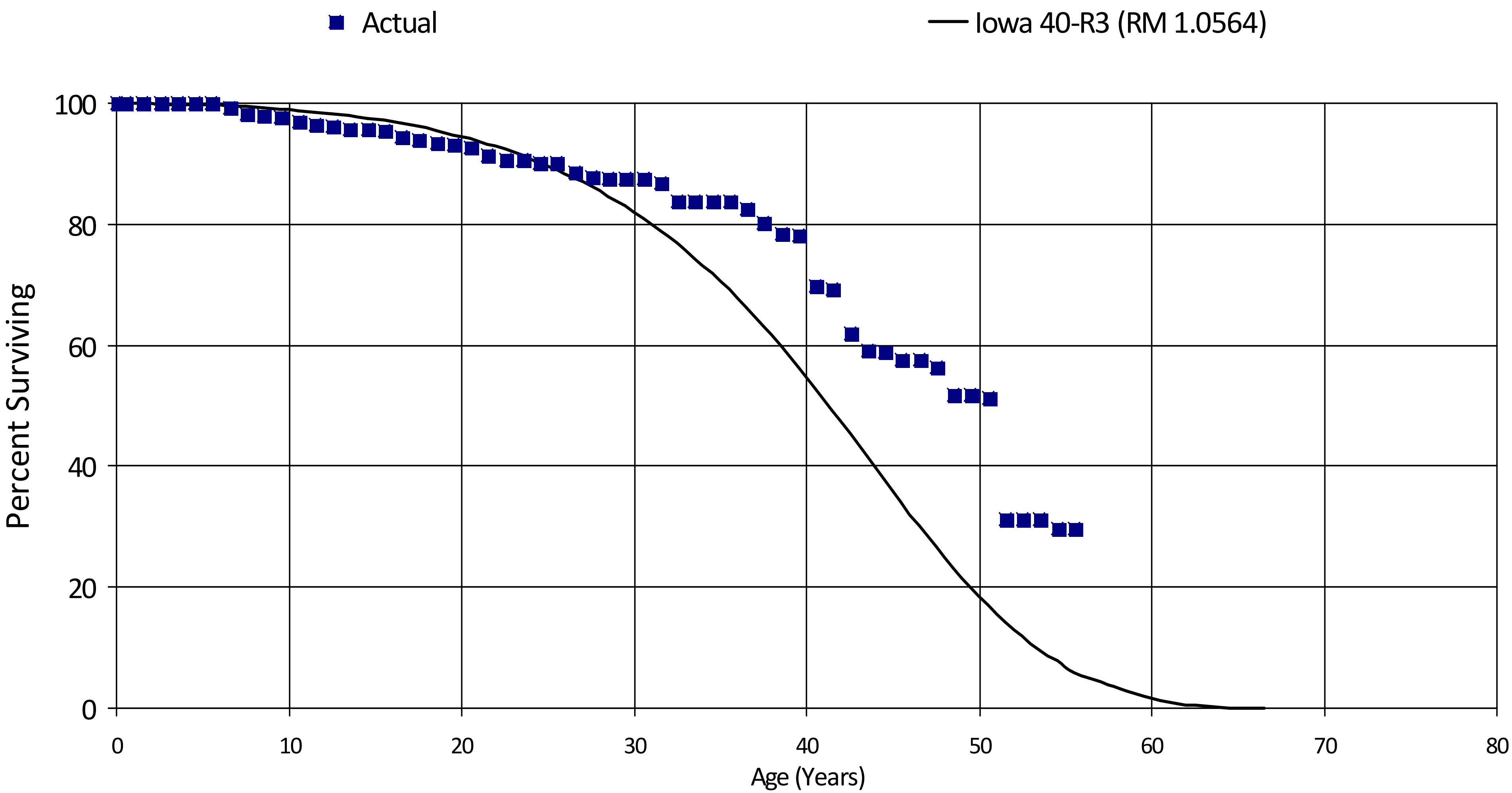
58.5	0	0	0.00000	0.00000	99.79
	Totals:	146,264			

Enbridge Gas Inc.

Account 452.00 - Underground Storage - Structures and Improvements

Placement Band - 1965 - 2021 Experience Band - 2011 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 452.00 - Underground Storage - Structures and Improvements

Placement Band - 1965 - 2021 Experience Band - 2011 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	108,432,725	0	0.00000	1.00000	100.00
0.5	105,031,866	0	0.00000	1.00000	100.00
1.5	104,534,510	0	0.00000	1.00000	100.00
2.5	103,581,047	0	0.00000	1.00000	100.00
3.5	100,747,804	59,143	0.00059	0.99941	100.00
4.5	93,386,277	31,722	0.00034	0.99966	99.94
5.5	77,759,287	428,727	0.00551	0.99449	99.91
6.5	76,470,025	830,143	0.01086	0.98914	99.36
7.5	72,743,550	193,145	0.00266	0.99734	98.28
8.5	72,101,933	319,405	0.00443	0.99557	98.02
9.5	68,688,868	372,181	0.00542	0.99458	97.59
10.5	65,668,063	341,926	0.00521	0.99479	97.06
11.5	62,095,084	220,267	0.00355	0.99645	96.55
12.5	60,746,889	252,953	0.00416	0.99584	96.21
13.5	58,471,788	155,682	0.00266	0.99734	95.81
14.5	58,150,957	136,327	0.00234	0.99766	95.56
15.5	51,880,304	478,263	0.00922	0.99078	95.34
16.5	51,281,706	351,583	0.00686	0.99314	94.46
17.5	50,924,988	255,901	0.00503	0.99497	93.81
18.5	50,616,526	151,979	0.00300	0.99700	93.34
19.5	50,432,138	196,618	0.00390	0.99610	93.06
20.5	49,973,274	756,306	0.01513	0.98487	92.70
21.5	48,779,436	343,379	0.00704	0.99296	91.30
22.5	48,079,135	32,327	0.00067	0.99933	90.66
23.5	46,949,286	203,128	0.00433	0.99567	90.60
24.5	42,765,460	95,074	0.00222	0.99778	90.21
25.5	41,976,191	630,561	0.01502	0.98498	90.01
26.5	39,578,780	411,221	0.01039	0.98961	88.66

Enbridge Gas Inc.

Account 452.00 - Underground Storage - Structures and Improvements

Placement Band - 1965 - 2021   Experience Band - 2011 - 2021

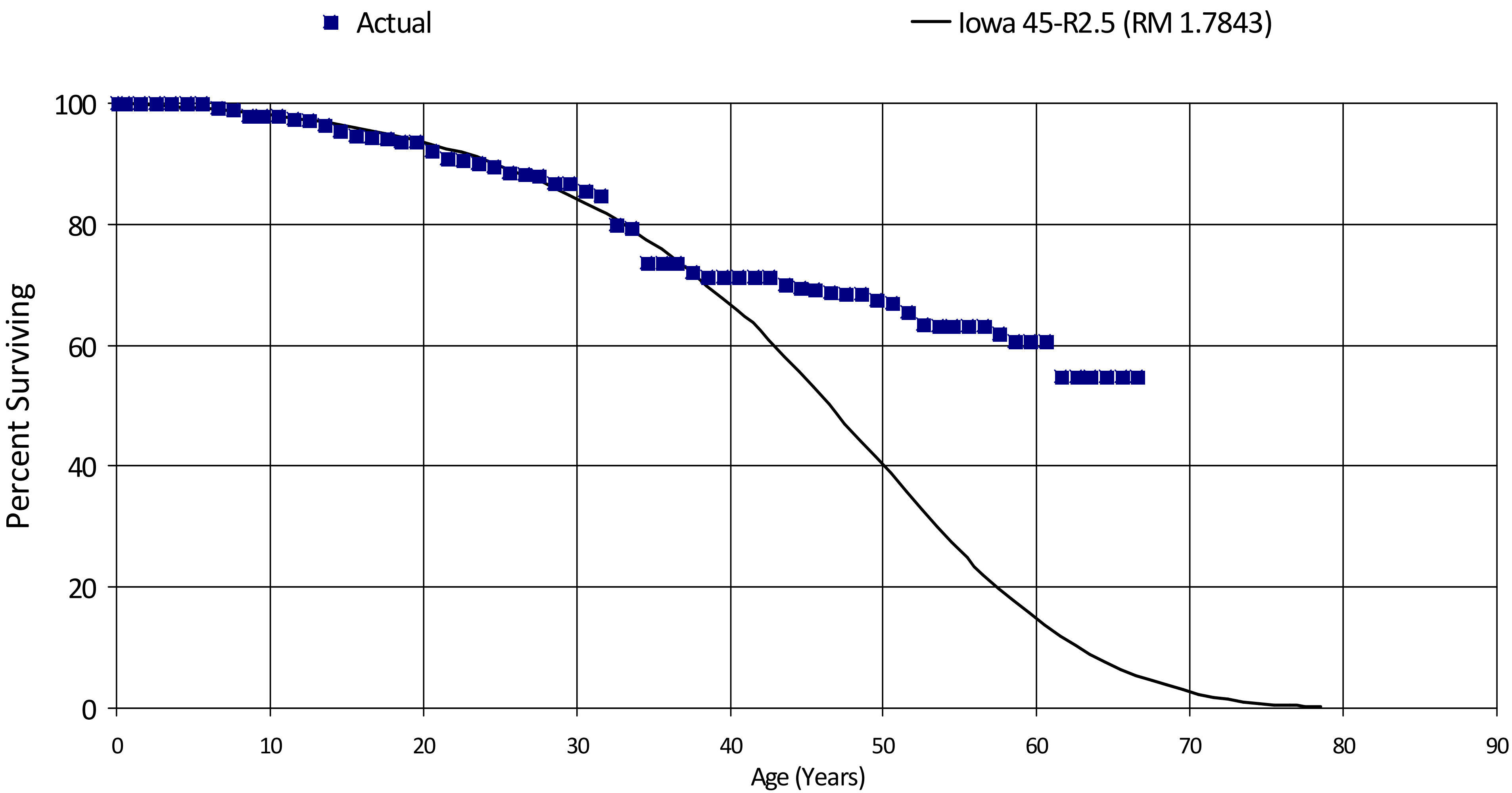
27.5	38,122,061	28,833	0.00076	0.99924	87.74
28.5	33,473,699	30,693	0.00092	0.99908	87.67
29.5	32,000,705	36,561	0.00114	0.99886	87.59
30.5	21,273,496	145,142	0.00682	0.99318	87.49
31.5	20,743,822	740,010	0.03567	0.96433	86.89
32.5	12,828,528	6,330	0.00049	0.99951	83.79
33.5	12,383,808	0	0.00000	1.00000	83.75
34.5	12,359,976	5,559	0.00045	0.99955	83.75
35.5	11,769,402	171,855	0.01460	0.98540	83.71
36.5	5,198,636	145,438	0.02798	0.97202	82.49
37.5	5,040,841	114,578	0.02273	0.97727	80.18
38.5	4,289,188	14,286	0.00333	0.99667	78.36
39.5	4,147,996	440,570	0.10621	0.89379	78.10
40.5	3,248,314	26,970	0.00830	0.99170	69.80
41.5	3,175,533	334,354	0.10529	0.89471	69.22
42.5	2,792,619	129,855	0.04650	0.95350	61.93
43.5	1,549,971	2,977	0.00192	0.99808	59.05
44.5	1,546,994	32,018	0.02070	0.97930	58.94
45.5	1,355,615	4,669	0.00344	0.99656	57.72
46.5	1,266,569	25,666	0.02026	0.97974	57.52
47.5	1,240,903	99,604	0.08027	0.91973	56.35
48.5	744,659	0	0.00000	1.00000	51.83
49.5	170,660	1,580	0.00926	0.99074	51.83
50.5	71,418	27,973	0.39168	0.60832	51.35
51.5	43,446	0	0.00000	1.00000	31.24
52.5	40,520	0	0.00000	1.00000	31.24
53.5	40,520	1,932	0.04768	0.95232	31.24
54.5	257	0	0.00000	1.00000	29.75
55.5	0	0	0.00000	0.00000	29.75
	Totals:	9,815,414			

Enbridge Gas Inc.

Account 453.00 - Underground Storage - Wells

Placement Band - 1930 - 2021 Experience Band - 2011 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 453.00 - Underground Storage - Wells

Placement Band - 1930 - 2021 Experience Band - 2011 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	158,002,139	0	0.00000	1.00000	100.00
0.5	133,022,924	4,828	0.00004	0.99996	100.00
1.5	124,490,387	41,341	0.00033	0.99967	100.00
2.5	123,949,760	0	0.00000	1.00000	99.97
3.5	112,204,825	0	0.00000	1.00000	99.97
4.5	111,665,142	0	0.00000	1.00000	99.97
5.5	104,599,081	818,539	0.00783	0.99217	99.97
6.5	101,756,537	227,120	0.00223	0.99777	99.19
7.5	99,242,657	889,954	0.00897	0.99103	98.97
8.5	97,142,511	4,432	0.00005	0.99995	98.08
9.5	93,526,922	126,331	0.00135	0.99865	98.08
10.5	92,473,945	415,940	0.00450	0.99550	97.95
11.5	80,432,272	181,465	0.00226	0.99774	97.51
12.5	78,474,853	629,128	0.00802	0.99198	97.29
13.5	76,636,827	940,778	0.01228	0.98772	96.51
14.5	75,124,270	440,507	0.00586	0.99414	95.32
15.5	73,686,783	266,774	0.00362	0.99638	94.76
16.5	72,059,429	210,673	0.00292	0.99708	94.42
17.5	71,396,502	290,880	0.00407	0.99593	94.14
18.5	69,996,183	160,611	0.00229	0.99771	93.76
19.5	59,492,825	933,861	0.01570	0.98430	93.55
20.5	58,023,253	749,491	0.01292	0.98708	92.08
21.5	56,650,885	171,316	0.00302	0.99698	90.89
22.5	53,598,100	237,561	0.00443	0.99557	90.62
23.5	52,324,644	353,274	0.00675	0.99325	90.22
24.5	47,379,607	578,666	0.01221	0.98779	89.61
25.5	41,714,773	35,623	0.00085	0.99915	88.52
26.5	36,459,278	162,303	0.00445	0.99555	88.44

Enbridge Gas Inc.

Account 453.00 - Underground Storage - Wells

Placement Band - 1930 - 2021 Experience Band - 2011 - 2021

27.5	35,831,583	532,203	0.01485	0.98515	88.05
28.5	33,250,512	0	0.00000	1.00000	86.74
29.5	31,049,163	456,394	0.01470	0.98530	86.74
30.5	30,225,404	278,534	0.00922	0.99078	85.46
31.5	25,811,151	1,438,107	0.05572	0.94428	84.67
32.5	21,998,409	137,250	0.00624	0.99376	79.95
33.5	18,797,414	1,355,602	0.07212	0.92788	79.45
34.5	14,810,303	0	0.00000	1.00000	73.72
35.5	13,792,395	22,367	0.00162	0.99838	73.72
36.5	13,195,477	276,851	0.02098	0.97902	73.60
37.5	11,925,062	129,762	0.01088	0.98912	72.06
38.5	10,843,020	0	0.00000	1.00000	71.28
39.5	10,843,020	0	0.00000	1.00000	71.28
40.5	10,744,843	0	0.00000	1.00000	71.28
41.5	10,615,590	0	0.00000	1.00000	71.28
42.5	10,571,795	195,686	0.01851	0.98149	71.28
43.5	10,086,805	44,320	0.00439	0.99561	69.96
44.5	8,960,763	53,284	0.00595	0.99405	69.65
45.5	8,851,197	67,908	0.00767	0.99233	69.24
46.5	8,600,778	31,021	0.00361	0.99639	68.71
47.5	7,907,212	0	0.00000	1.00000	68.46
48.5	7,794,391	117,627	0.01509	0.98491	68.46
49.5	7,495,048	44,320	0.00591	0.99409	67.43
50.5	5,633,026	136,188	0.02418	0.97582	67.03
51.5	5,249,133	149,930	0.02856	0.97144	65.41
52.5	4,749,862	31,021	0.00653	0.99347	63.54
53.5	4,566,684	0	0.00000	1.00000	63.13
54.5	4,566,684	0	0.00000	1.00000	63.13
55.5	4,269,352	0	0.00000	1.00000	63.13
56.5	4,234,632	82,904	0.01958	0.98042	63.13
57.5	3,768,239	82,023	0.02177	0.97823	61.89

Enbridge Gas Inc.

Account 453.00 - Underground Storage - Wells

Placement Band - 1930 - 2021 Experience Band - 2011 - 2021

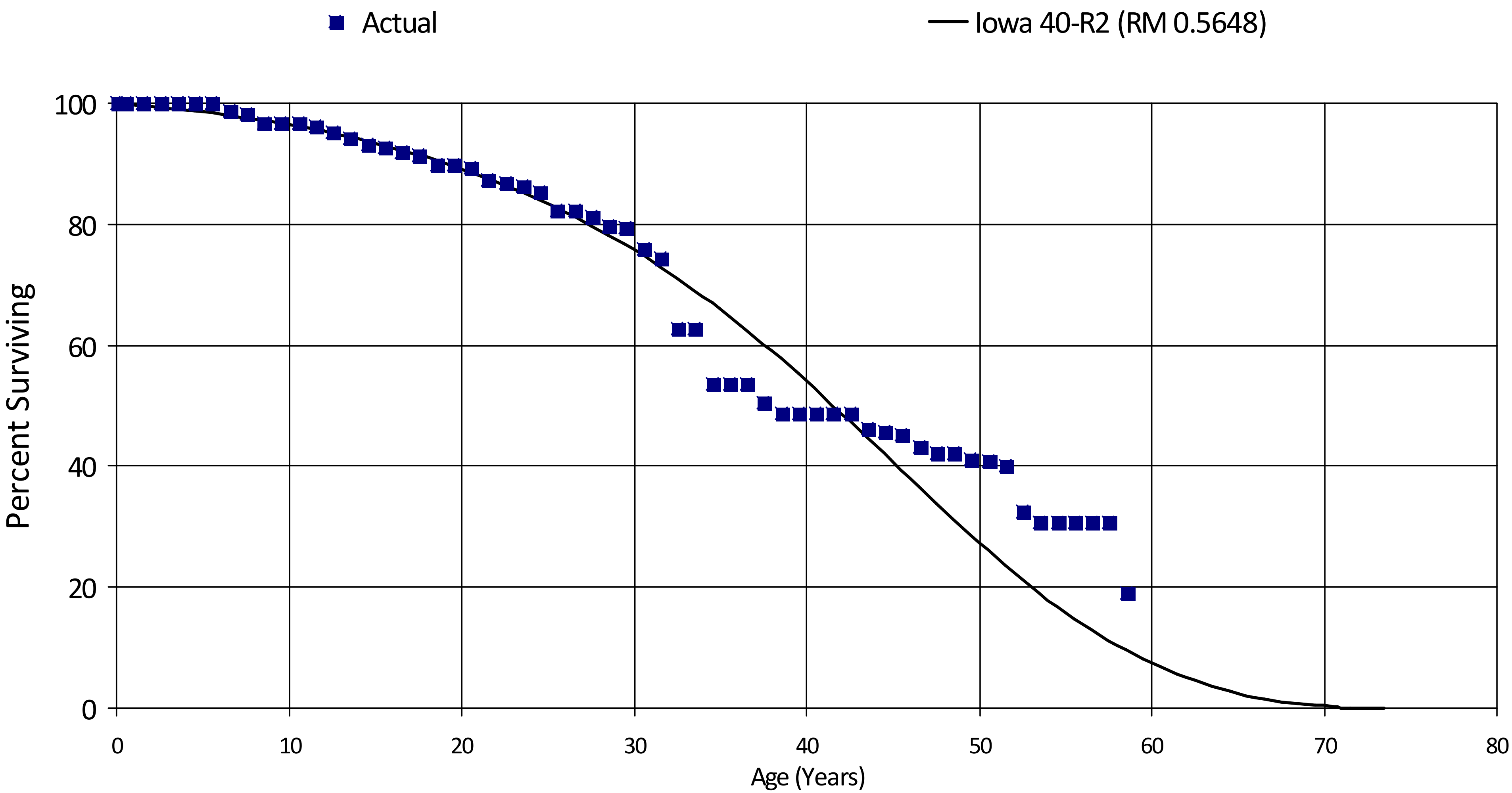
58.5	3,531,548	0	0.00000	1.00000	60.54
59.5	3,454,424	0	0.00000	1.00000	60.54
60.5	3,454,424	323,051	0.09352	0.90648	60.54
61.5	3,075,252	0	0.00000	1.00000	54.88
62.5	2,861,509	0	0.00000	1.00000	54.88
63.5	2,861,509	0	0.00000	1.00000	54.88
64.5	2,192,763	0	0.00000	1.00000	54.88
65.5	2,192,763	0	0.00000	1.00000	54.88
66.5	1,371,496	0	0.00000	1.00000	54.88
	Totals:	14,857,749			

Enbridge Gas Inc.

Account 454.00 - Underground Storage - Well Equipment

Placement Band - 1949 - 2021 Experience Band - 2015 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 454.00 - Underground Storage - Well Equipment

Placement Band - 1949 - 2021 Experience Band - 2015 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	17,619,138	0	0.00000	1.00000	100.00
0.5	17,324,017	0	0.00000	1.00000	100.00
1.5	15,880,210	0	0.00000	1.00000	100.00
2.5	15,880,210	0	0.00000	1.00000	100.00
3.5	14,740,204	0	0.00000	1.00000	100.00
4.5	14,740,204	0	0.00000	1.00000	100.00
5.5	13,620,761	186,059	0.01366	0.98634	100.00
6.5	12,491,735	65,012	0.00520	0.99480	98.63
7.5	11,983,676	181,780	0.01517	0.98483	98.12
8.5	11,585,391	0	0.00000	1.00000	96.63
9.5	11,060,509	0	0.00000	1.00000	96.63
10.5	10,962,004	42,444	0.00387	0.99613	96.63
11.5	10,310,151	105,777	0.01026	0.98974	96.26
12.5	9,751,815	107,455	0.01102	0.98898	95.27
13.5	9,516,572	99,519	0.01046	0.98954	94.22
14.5	9,378,828	62,358	0.00665	0.99335	93.23
15.5	9,226,146	82,988	0.00899	0.99101	92.61
16.5	8,957,109	44,145	0.00493	0.99507	91.78
17.5	8,904,251	151,747	0.01704	0.98296	91.33
18.5	8,548,850	0	0.00000	1.00000	89.77
19.5	8,534,821	33,472	0.00392	0.99608	89.77
20.5	8,444,014	188,798	0.02236	0.97764	89.42
21.5	8,184,906	46,443	0.00567	0.99433	87.42
22.5	7,512,075	50,093	0.00667	0.99333	86.92
23.5	7,154,710	91,668	0.01281	0.98719	86.34
24.5	6,298,648	212,778	0.03378	0.96622	85.23
25.5	5,292,626	0	0.00000	1.00000	82.35
26.5	5,292,626	72,974	0.01379	0.98621	82.35

Enbridge Gas Inc.

Account 454.00 - Underground Storage - Well Equipment

Placement Band - 1949 - 2021   Experience Band - 2015 - 2021

27.5	5,203,214	91,629	0.01761	0.98239	81.21
28.5	5,111,585	22,551	0.00441	0.99559	79.78
29.5	4,960,804	213,488	0.04303	0.95697	79.43
30.5	4,747,316	103,449	0.02179	0.97821	76.01
31.5	4,462,341	693,727	0.15546	0.84454	74.35
32.5	3,668,986	0	0.00000	1.00000	62.79
33.5	3,522,095	514,475	0.14607	0.85393	62.79
34.5	2,407,194	0	0.00000	1.00000	53.62
35.5	2,407,194	0	0.00000	1.00000	53.62
36.5	2,407,194	138,893	0.05770	0.94230	53.62
37.5	1,984,284	69,309	0.03493	0.96507	50.53
38.5	1,741,679	0	0.00000	1.00000	48.76
39.5	1,741,679	0	0.00000	1.00000	48.76
40.5	1,741,679	0	0.00000	1.00000	48.76
41.5	1,704,102	0	0.00000	1.00000	48.76
42.5	1,704,102	92,099	0.05405	0.94595	48.76
43.5	1,471,185	11,386	0.00774	0.99226	46.12
44.5	1,459,798	17,067	0.01169	0.98831	45.76
45.5	1,407,993	67,698	0.04808	0.95192	45.23
46.5	1,299,339	28,633	0.02204	0.97796	43.06
47.5	1,186,816	0	0.00000	1.00000	42.11
48.5	1,133,669	23,592	0.02081	0.97919	42.11
49.5	1,067,206	11,386	0.01067	0.98933	41.23
50.5	967,417	17,067	0.01764	0.98236	40.79
51.5	922,819	175,863	0.19057	0.80943	40.07
52.5	539,722	28,633	0.05305	0.94695	32.43
53.5	422,707	0	0.00000	1.00000	30.71
54.5	422,707	0	0.00000	1.00000	30.71
55.5	331,836	0	0.00000	1.00000	30.71
56.5	331,836	0	0.00000	1.00000	30.71
57.5	286,102	108,164	0.37806	0.62194	30.71

Enbridge Gas Inc.

Account 454.00 - Underground Storage - Well Equipment

Placement Band - 1949 - 2021 Experience Band - 2015 - 2021

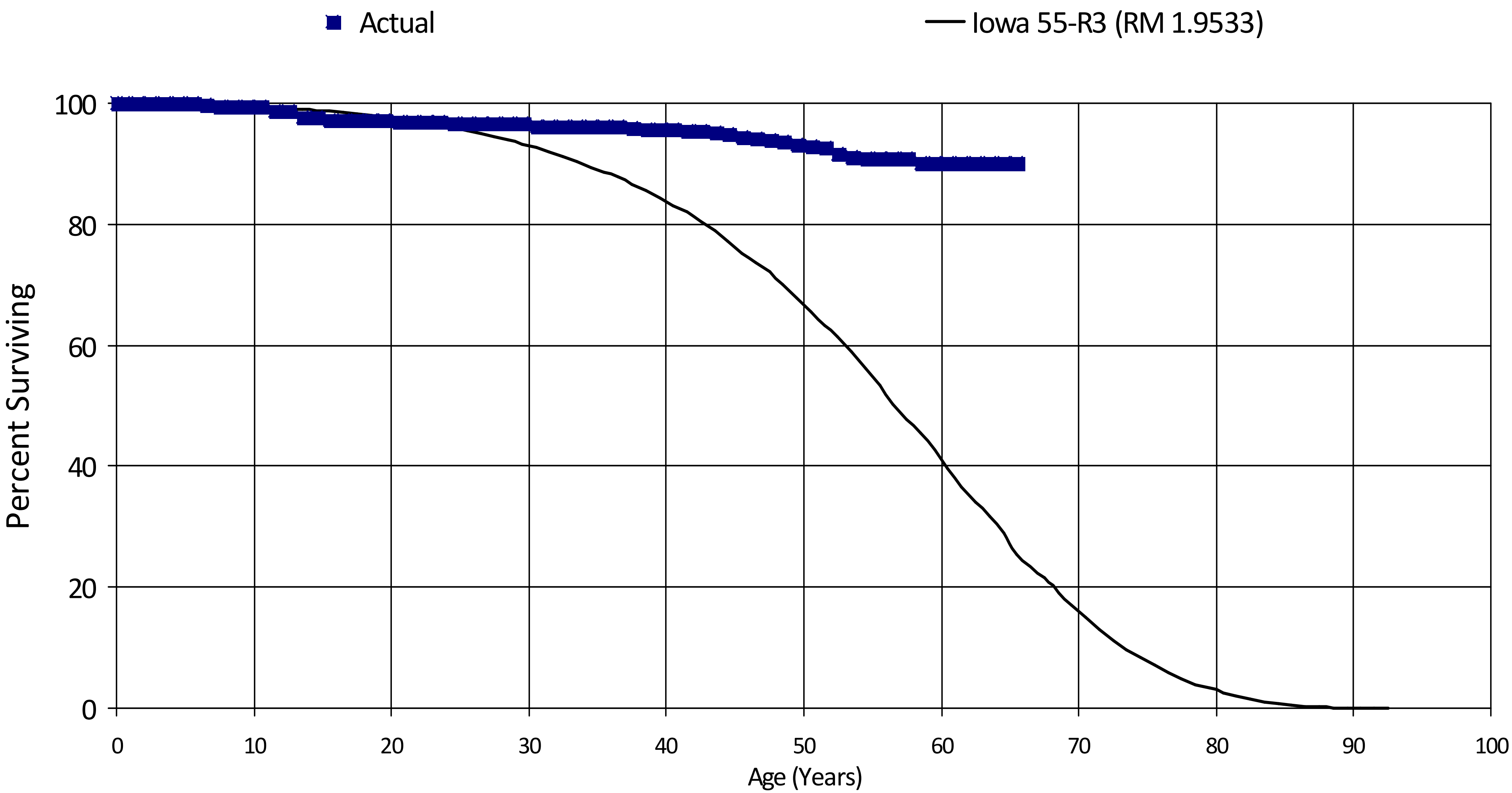
58.5	0	0	0.00000	0.00000	19.10
	Totals:	4,254,619			

Enbridge Gas Inc.

Account 455.00 - Underground Storage - Field Lines

Placement Band - 1955 - 2021   Experience Band - 2011 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 455.00 - Underground Storage - Field Lines

Placement Band - 1955 - 2021   Experience Band - 2011 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	206,577,322	0	0.00000	1.00000	100.00
0.5	191,481,051	0	0.00000	1.00000	100.00
1.5	181,967,890	0	0.00000	1.00000	100.00
2.5	178,921,797	0	0.00000	1.00000	100.00
3.5	172,302,790	0	0.00000	1.00000	100.00
4.5	167,907,887	3,033	0.00002	0.99998	100.00
5.5	163,052,111	577,359	0.00354	0.99646	100.00
6.5	151,831,687	126,293	0.00083	0.99917	99.65
7.5	149,970,857	95,638	0.00064	0.99936	99.57
8.5	142,963,883	173,449	0.00121	0.99879	99.51
9.5	139,887,416	22,384	0.00016	0.99984	99.39
10.5	118,177,454	703,709	0.00595	0.99405	99.37
11.5	116,215,181	4,576	0.00004	0.99996	98.78
12.5	115,241,111	1,236,413	0.01073	0.98927	98.78
13.5	106,755,815	74,778	0.00070	0.99930	97.72
14.5	106,001,754	406,699	0.00384	0.99616	97.65
15.5	103,395,112	0	0.00000	1.00000	97.28
16.5	102,576,903	0	0.00000	1.00000	97.28
17.5	99,805,914	0	0.00000	1.00000	97.28
18.5	97,427,997	0	0.00000	1.00000	97.28
19.5	90,862,651	330,084	0.00363	0.99637	97.28
20.5	85,241,862	84,039	0.00099	0.99901	96.93
21.5	83,839,308	0	0.00000	1.00000	96.83
22.5	76,275,424	0	0.00000	1.00000	96.83
23.5	74,958,441	5,743	0.00008	0.99992	96.83
24.5	66,081,116	68,385	0.00103	0.99897	96.82
25.5	62,437,970	0	0.00000	1.00000	96.72
26.5	62,417,231	0	0.00000	1.00000	96.72

Enbridge Gas Inc.

Account 455.00 - Underground Storage - Field Lines

Placement Band - 1955 - 2021 Experience Band - 2011 - 2021

27.5	60,972,808	19,215	0.00032	0.99968	96.72
28.5	60,464,355	28,718	0.00047	0.99953	96.69
29.5	28,382,434	110,073	0.00388	0.99612	96.64
30.5	23,965,512	3,370	0.00014	0.99986	96.27
31.5	23,365,127	28,424	0.00122	0.99878	96.26
32.5	23,131,213	0	0.00000	1.00000	96.14
33.5	21,898,846	14,303	0.00065	0.99935	96.14
34.5	15,554,009	0	0.00000	1.00000	96.08
35.5	15,531,029	0	0.00000	1.00000	96.08
36.5	14,769,077	31,094	0.00211	0.99789	96.08
37.5	14,573,303	45,549	0.00313	0.99687	95.88
38.5	14,081,097	0	0.00000	1.00000	95.58
39.5	13,956,804	0	0.00000	1.00000	95.58
40.5	13,956,804	13,026	0.00093	0.99907	95.58
41.5	13,939,518	0	0.00000	1.00000	95.49
42.5	13,912,605	27,724	0.00199	0.99801	95.49
43.5	13,867,570	42,408	0.00306	0.99694	95.30
44.5	11,796,232	64,391	0.00546	0.99454	95.01
45.5	7,213,236	34,028	0.00472	0.99528	94.49
46.5	7,093,374	13,026	0.00184	0.99816	94.04
47.5	7,029,677	17,832	0.00254	0.99746	93.87
48.5	6,954,070	40,660	0.00585	0.99415	93.63
49.5	6,913,410	11,061	0.00160	0.99840	93.08
50.5	6,696,244	18,576	0.00277	0.99723	92.93
51.5	6,636,943	79,139	0.01192	0.98808	92.67
52.5	6,528,757	28,167	0.00431	0.99569	91.57
53.5	6,416,725	17,681	0.00276	0.99724	91.18
54.5	6,369,897	4,422	0.00069	0.99931	90.93
55.5	6,301,154	0	0.00000	1.00000	90.87
56.5	6,281,115	0	0.00000	1.00000	90.87
57.5	6,263,924	51,774	0.00827	0.99173	90.87

Enbridge Gas Inc.

Account 455.00 - Underground Storage - Field Lines

Placement Band - 1955 - 2021 Experience Band - 2011 - 2021

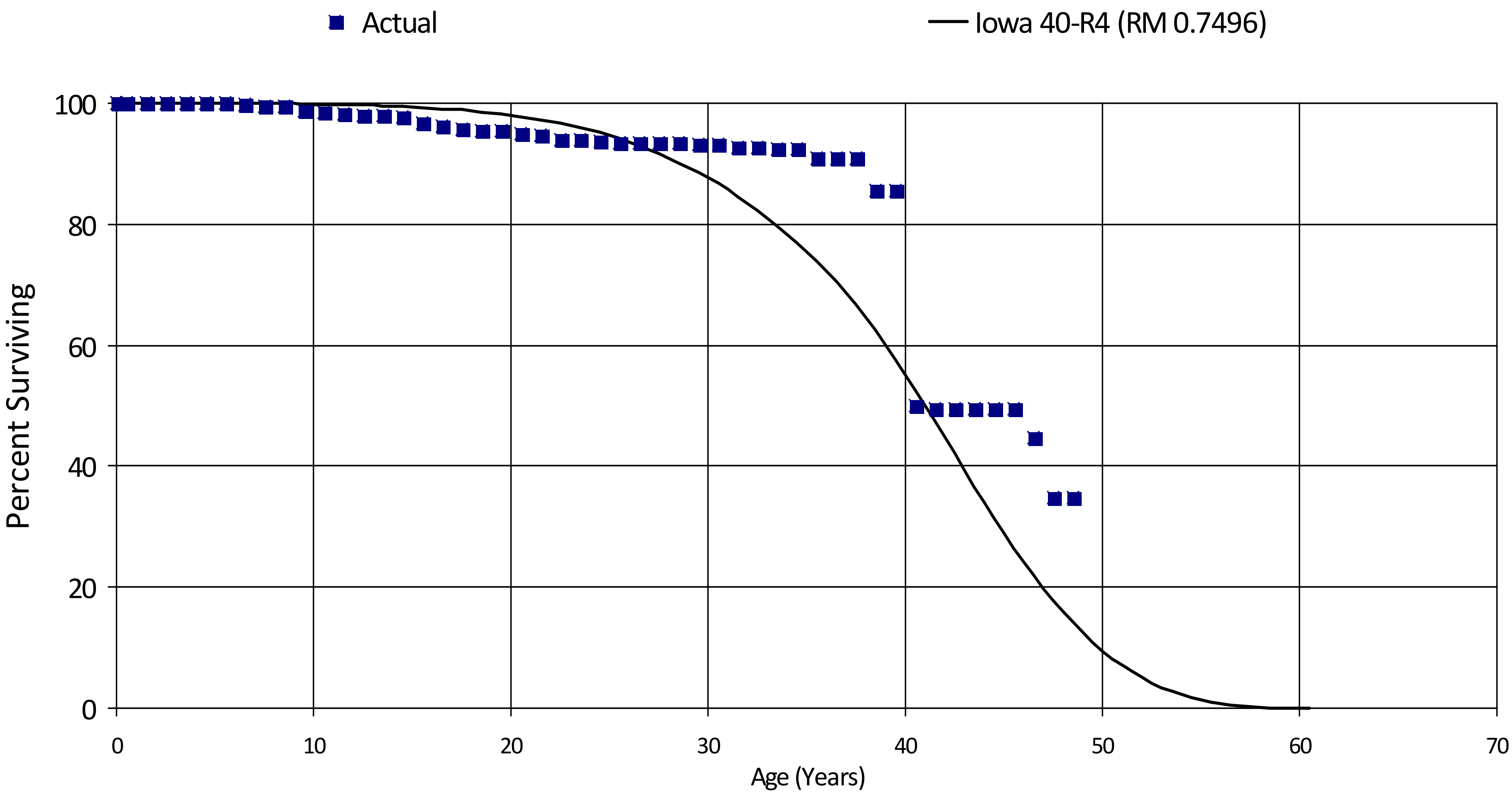
58.5	2,080,913	0	0.00000	1.00000	90.12
59.5	2,080,913	0	0.00000	1.00000	90.12
60.5	421,375	0	0.00000	1.00000	90.12
61.5	417,358	0	0.00000	1.00000	90.12
62.5	277,122	0	0.00000	1.00000	90.12
63.5	277,122	0	0.00000	1.00000	90.12
64.5	272,766	0	0.00000	1.00000	90.12
65.5	272,766	0	0.00000	1.00000	90.12
	Totals:	4,657,243			

Enbridge Gas Inc.

Account 456.00 - Underground Storage - Compressor Equipment

Placement Band - 1950 - 2021 Experience Band - 2010 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 456.00 - Underground Storage - Compressor Equipment

Placement Band - 1950 - 2021   Experience Band - 2010 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	733,513,789	0	0.00000	1.00000	100.00
0.5	681,416,498	0	0.00000	1.00000	100.00
1.5	668,935,562	0	0.00000	1.00000	100.00
2.5	664,688,765	12,782	0.00002	0.99998	100.00
3.5	651,306,660	0	0.00000	1.00000	100.00
4.5	462,141,366	574,712	0.00124	0.99876	100.00
5.5	390,363,496	436,875	0.00112	0.99888	99.88
6.5	374,394,577	1,437,478	0.00384	0.99616	99.77
7.5	364,154,635	1,271	0.00000	1.00000	99.39
8.5	360,314,364	2,094,644	0.00581	0.99419	99.39
9.5	357,476,825	960,053	0.00269	0.99731	98.81
10.5	333,782,388	1,094,674	0.00328	0.99672	98.54
11.5	313,724,435	824,749	0.00263	0.99737	98.22
12.5	304,669,420	143,622	0.00047	0.99953	97.96
13.5	299,258,563	371,725	0.00124	0.99876	97.91
14.5	296,518,167	3,532,193	0.01191	0.98809	97.79
15.5	249,772,938	1,383,768	0.00554	0.99446	96.63
16.5	245,453,111	935,253	0.00381	0.99619	96.09
17.5	242,095,387	697,244	0.00288	0.99712	95.72
18.5	237,603,717	89,798	0.00038	0.99962	95.44
19.5	235,191,994	868,138	0.00369	0.99631	95.40
20.5	232,930,431	1,203,486	0.00517	0.99483	95.05
21.5	226,738,828	1,680,544	0.00741	0.99259	94.56
22.5	220,404,238	43,568	0.00020	0.99980	93.86
23.5	218,969,006	193,746	0.00088	0.99912	93.84
24.5	207,135,108	537,423	0.00259	0.99741	93.76
25.5	161,216,656	55,143	0.00034	0.99966	93.52
26.5	150,493,674	297,242	0.00198	0.99802	93.49

Enbridge Gas Inc.

Account 456.00 - Underground Storage - Compressor Equipment

Placement Band - 1950 - 2021 Experience Band - 2010 - 2021

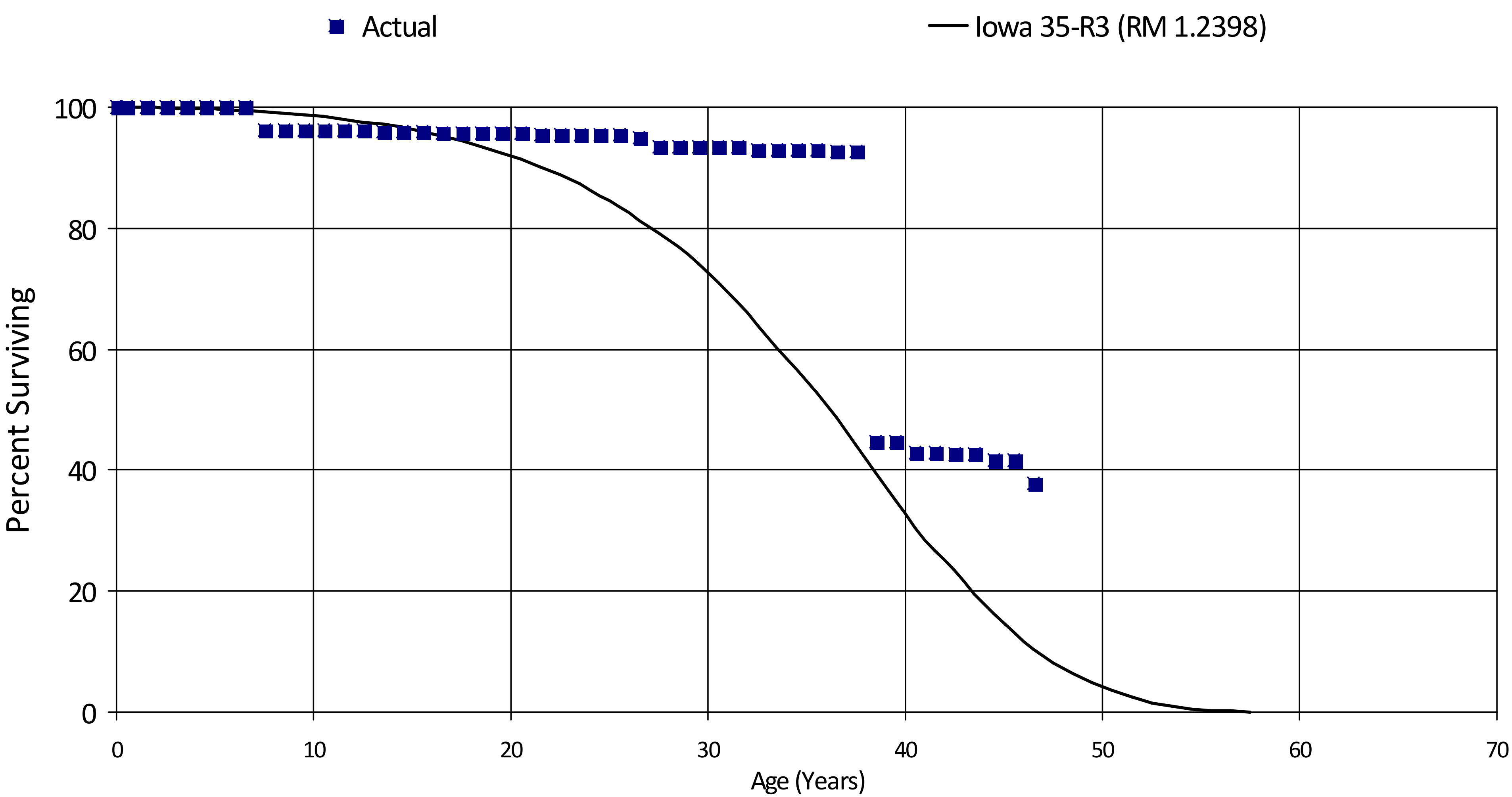
27.5	148,419,924	22,333	0.00015	0.99985	93.30
28.5	145,923,724	127,817	0.00088	0.99912	93.29
29.5	111,931,381	143,381	0.00128	0.99872	93.21
30.5	108,720,193	599,032	0.00551	0.99449	93.09
31.5	87,465,546	55,143	0.00063	0.99937	92.58
32.5	86,255,603	237,577	0.00275	0.99725	92.52
33.5	72,568,248	0	0.00000	1.00000	92.27
34.5	72,376,707	1,127,816	0.01558	0.98442	92.27
35.5	71,074,148	2,969	0.00004	0.99996	90.83
36.5	68,035,252	66,846	0.00098	0.99902	90.83
37.5	67,931,580	3,841,742	0.05655	0.94345	90.74
38.5	64,054,233	87,107	0.00136	0.99864	85.61
39.5	42,413,148	17,626,792	0.41560	0.58440	85.49
40.5	20,928,899	237,601	0.01135	0.98865	49.96
41.5	20,157,295	0	0.00000	1.00000	49.39
42.5	20,157,295	6,110	0.00030	0.99970	49.39
43.5	20,151,185	0	0.00000	1.00000	49.38
44.5	20,151,185	0	0.00000	1.00000	49.38
45.5	19,281,365	1,859,692	0.09645	0.90355	49.38
46.5	13,860,929	3,031,445	0.21870	0.78130	44.62
47.5	10,829,484	0	0.00000	1.00000	34.86
48.5	7,769,984	6,110	0.00079	0.99921	34.86
	Totals:	48,549,644			

Enbridge Gas Inc.

Account 457.00 - Underground Storage - Measuring and Regulating Equipment

Placement Band - 1963 - 2021 Experience Band - 2010 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 457.00 - Underground Storage - Measuring and Regulating Equipment

Placement Band - 1963 - 2021   Experience Band - 2010 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	87,327,319	0	0.00000	1.00000	100.00
0.5	83,372,329	0	0.00000	1.00000	100.00
1.5	83,040,818	0	0.00000	1.00000	100.00
2.5	81,047,272	0	0.00000	1.00000	100.00
3.5	80,449,031	0	0.00000	1.00000	100.00
4.5	77,751,619	0	0.00000	1.00000	100.00
5.5	74,620,991	0	0.00000	1.00000	100.00
6.5	74,350,746	2,759,107	0.03711	0.96289	100.00
7.5	70,746,252	33,986	0.00048	0.99952	96.29
8.5	70,115,763	47,562	0.00068	0.99932	96.24
9.5	63,411,036	0	0.00000	1.00000	96.17
10.5	62,418,345	29,631	0.00047	0.99953	96.17
11.5	60,733,019	0	0.00000	1.00000	96.12
12.5	59,212,840	48,047	0.00081	0.99919	96.12
13.5	58,968,305	62,494	0.00106	0.99894	96.04
14.5	58,763,160	32,727	0.00056	0.99944	95.94
15.5	57,065,451	55,704	0.00098	0.99902	95.89
16.5	56,138,168	0	0.00000	1.00000	95.80
17.5	56,138,168	65,919	0.00117	0.99883	95.80
18.5	55,476,941	3,840	0.00007	0.99993	95.69
19.5	54,399,301	0	0.00000	1.00000	95.68
20.5	50,206,157	71,671	0.00143	0.99857	95.68
21.5	39,230,270	0	0.00000	1.00000	95.54
22.5	36,027,423	0	0.00000	1.00000	95.54
23.5	36,027,423	17,872	0.00050	0.99950	95.54
24.5	33,273,772	3,840	0.00012	0.99988	95.49
25.5	32,868,678	149,602	0.00455	0.99545	95.48
26.5	32,114,010	570,972	0.01778	0.98222	95.05

Enbridge Gas Inc.

Account 457.00 - Underground Storage - Measuring and Regulating Equipment

Placement Band - 1963 - 2021 Experience Band - 2010 - 2021

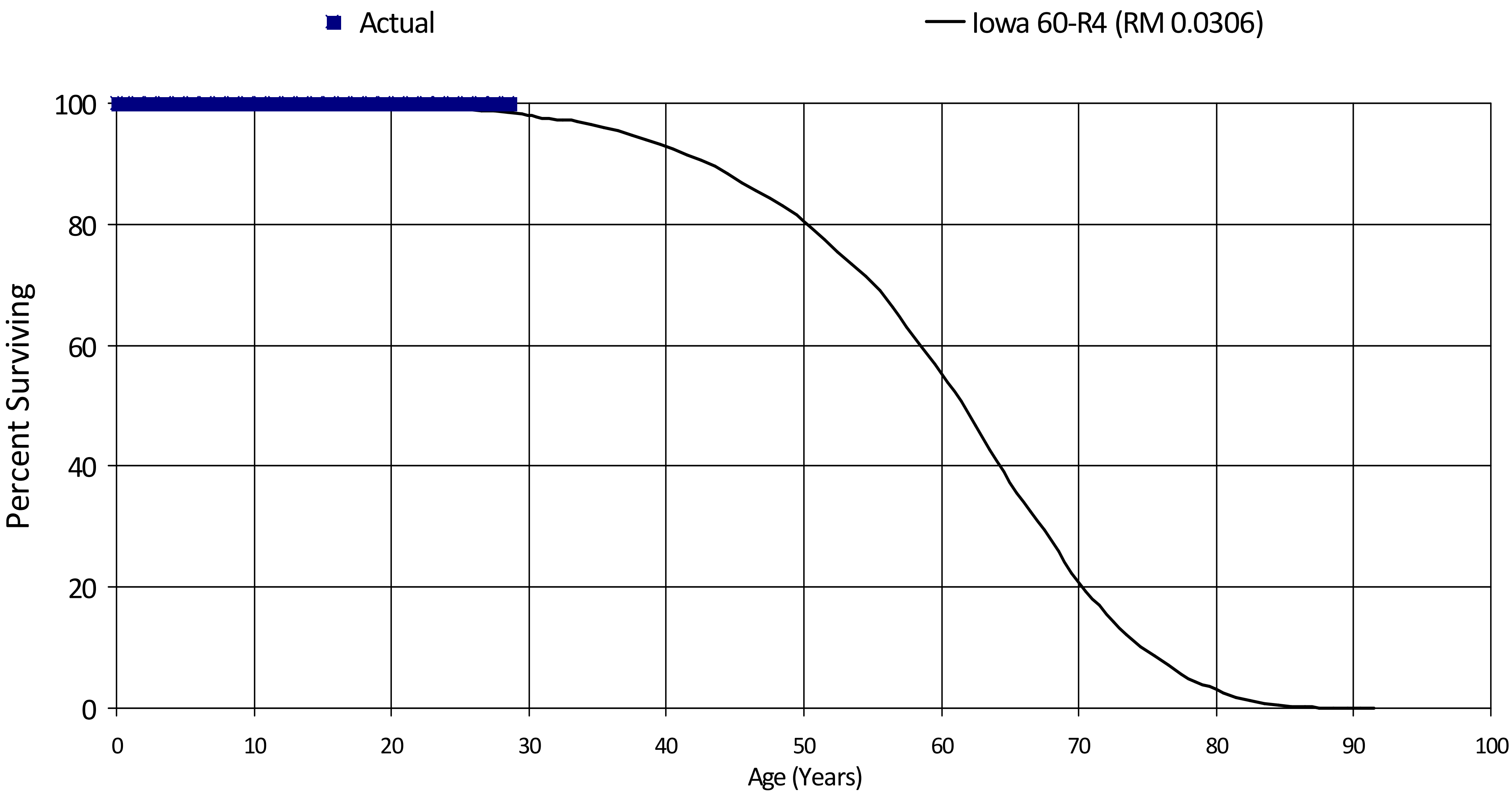
27.5	31,096,563	0	0.00000	1.00000	93.36
28.5	28,748,903	0	0.00000	1.00000	93.36
29.5	25,253,022	0	0.00000	1.00000	93.36
30.5	18,229,749	0	0.00000	1.00000	93.36
31.5	14,696,781	85,376	0.00581	0.99419	93.36
32.5	13,630,600	5,991	0.00044	0.99956	92.82
33.5	11,755,162	0	0.00000	1.00000	92.78
34.5	10,810,175	0	0.00000	1.00000	92.78
35.5	10,810,175	19,236	0.00178	0.99822	92.78
36.5	10,790,940	0	0.00000	1.00000	92.61
37.5	10,691,777	5,523,618	0.51662	0.48338	92.61
38.5	5,168,160	0	0.00000	1.00000	44.77
39.5	5,168,160	230,863	0.04467	0.95533	44.77
40.5	4,937,296	0	0.00000	1.00000	42.77
41.5	4,937,296	19,236	0.00390	0.99610	42.77
42.5	4,907,158	2	0.00000	1.00000	42.60
43.5	2,512,081	55,685	0.02217	0.97783	42.60
44.5	2,456,395	0	0.00000	1.00000	41.66
45.5	2,456,395	230,863	0.09398	0.90602	41.66
46.5	1,893,438	0	0.00000	1.00000	37.74
	Totals:	10,123,844			

Enbridge Gas Inc.

Account 461.00 - Transmission Plant - Land Rights Intangible

Placement Band - 1990 - 2021   Experience Band - 2021 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 461.00 - Transmission Plant - Land Rights Intangible

Placement Band - 1990 - 2021 Experience Band - 2021 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	88,171,402	0	0.00000	1.00000	100.00
0.5	87,376,869	0	0.00000	1.00000	100.00
1.5	86,400,843	0	0.00000	1.00000	100.00
2.5	82,111,855	0	0.00000	1.00000	100.00
3.5	81,924,358	0	0.00000	1.00000	100.00
4.5	78,404,574	0	0.00000	1.00000	100.00
5.5	42,392,414	0	0.00000	1.00000	100.00
6.5	40,572,014	0	0.00000	1.00000	100.00
7.5	39,776,319	0	0.00000	1.00000	100.00
8.5	38,360,880	0	0.00000	1.00000	100.00
9.5	38,359,574	0	0.00000	1.00000	100.00
10.5	38,195,399	0	0.00000	1.00000	100.00
11.5	38,123,985	0	0.00000	1.00000	100.00
12.5	34,319,085	0	0.00000	1.00000	100.00
13.5	34,276,317	0	0.00000	1.00000	100.00
14.5	31,952,739	0	0.00000	1.00000	100.00
15.5	25,817,952	0	0.00000	1.00000	100.00
16.5	25,807,476	0	0.00000	1.00000	100.00
17.5	25,777,322	0	0.00000	1.00000	100.00
18.5	25,614,047	0	0.00000	1.00000	100.00
19.5	23,232,289	0	0.00000	1.00000	100.00
20.5	22,055,817	0	0.00000	1.00000	100.00
21.5	22,055,559	0	0.00000	1.00000	100.00
22.5	21,343,867	0	0.00000	1.00000	100.00
23.5	20,840,075	0	0.00000	1.00000	100.00
24.5	20,778,028	0	0.00000	1.00000	100.00
25.5	19,386,831	0	0.00000	1.00000	100.00
26.5	19,079,402	0	0.00000	1.00000	100.00

Enbridge Gas Inc.

Account 461.00 - Transmission Plant - Land Rights Intangible

Placement Band - 1990 - 2021   Experience Band - 2021 - 2021

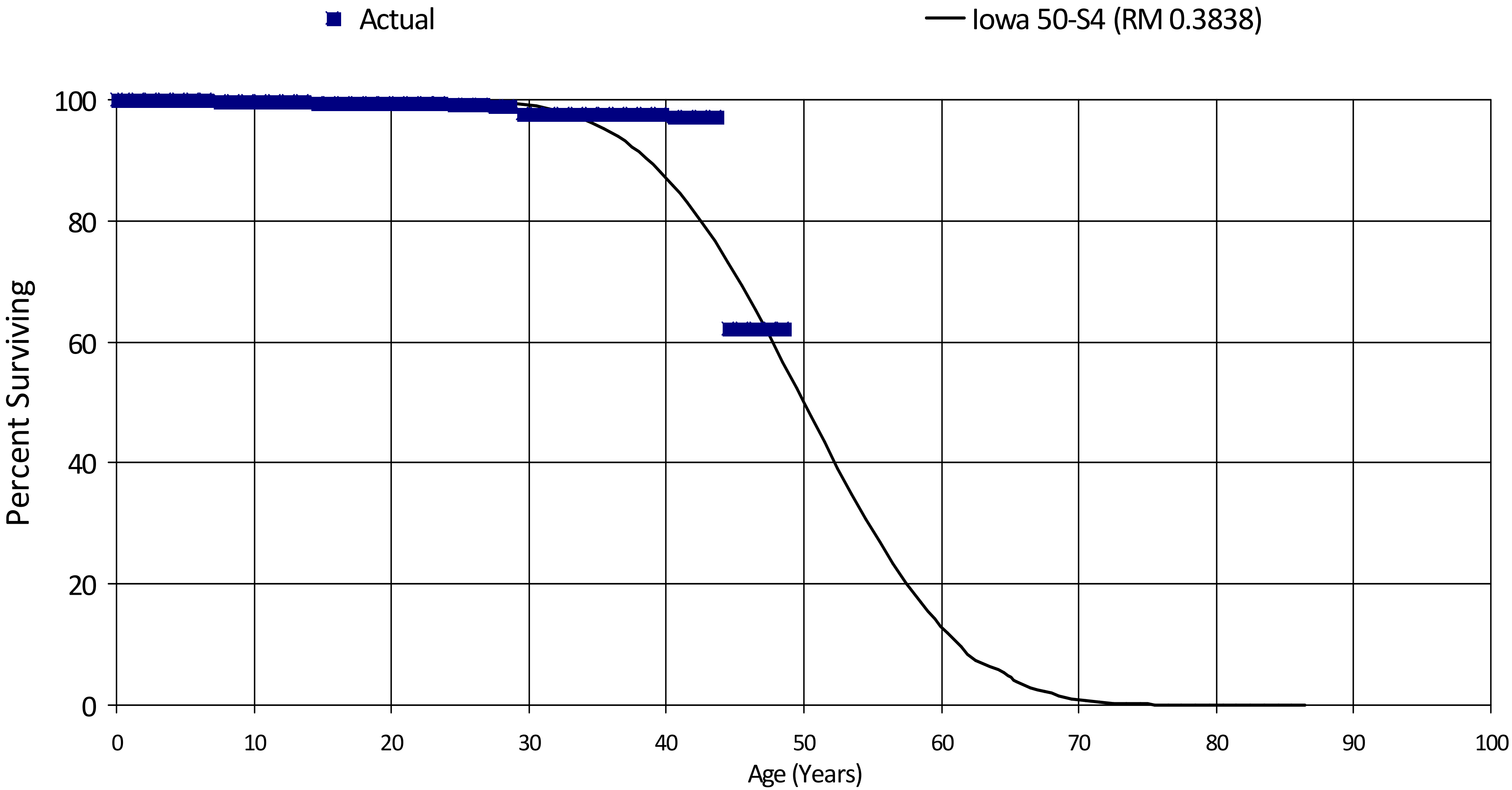
27.5	11,038	0	0.00000	1.00000	100.00
28.5	0	0	0.00000	0.00000	100.00
	Totals:	0			

Enbridge Gas Inc.

Account 462.00 - Transmission Plant - Compressor Structures and Improvements

Placement Band - 1958 - 2021 Experience Band - 2012 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 462.00 - Transmission Plant - Compressor Structures and Improvements

Placement Band - 1958 - 2021   Experience Band - 2012 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	166,278,357	0	0.00000	1.00000	100.00
0.5	156,024,325	0	0.00000	1.00000	100.00
1.5	155,756,182	0	0.00000	1.00000	100.00
2.5	155,566,945	23,946	0.00015	0.99985	100.00
3.5	155,388,218	9,466	0.00006	0.99994	99.98
4.5	120,756,104	0	0.00000	1.00000	99.97
5.5	97,453,155	0	0.00000	1.00000	99.97
6.5	63,739,314	72,288	0.00113	0.99887	99.97
7.5	43,666,004	0	0.00000	1.00000	99.86
8.5	42,854,517	0	0.00000	1.00000	99.86
9.5	42,444,448	0	0.00000	1.00000	99.86
10.5	41,839,809	1,613	0.00004	0.99996	99.86
11.5	41,527,308	37,352	0.00090	0.99910	99.86
12.5	40,485,292	0	0.00000	1.00000	99.77
13.5	38,310,255	123,178	0.00322	0.99678	99.77
14.5	33,102,704	0	0.00000	1.00000	99.45
15.5	33,070,886	0	0.00000	1.00000	99.45
16.5	33,051,670	0	0.00000	1.00000	99.45
17.5	32,854,284	0	0.00000	1.00000	99.45
18.5	32,854,284	0	0.00000	1.00000	99.45
19.5	32,833,926	0	0.00000	1.00000	99.45
20.5	32,809,767	0	0.00000	1.00000	99.45
21.5	32,689,192	6,989	0.00021	0.99979	99.45
22.5	32,682,203	0	0.00000	1.00000	99.43
23.5	32,521,430	49,823	0.00153	0.99847	99.43
24.5	32,243,618	0	0.00000	1.00000	99.28
25.5	32,243,618	0	0.00000	1.00000	99.28
26.5	31,614,180	109,663	0.00347	0.99653	99.28

Enbridge Gas Inc.

Account 462.00 - Transmission Plant - Compressor Structures and Improvements

Placement Band - 1958 - 2021 Experience Band - 2012 - 2021

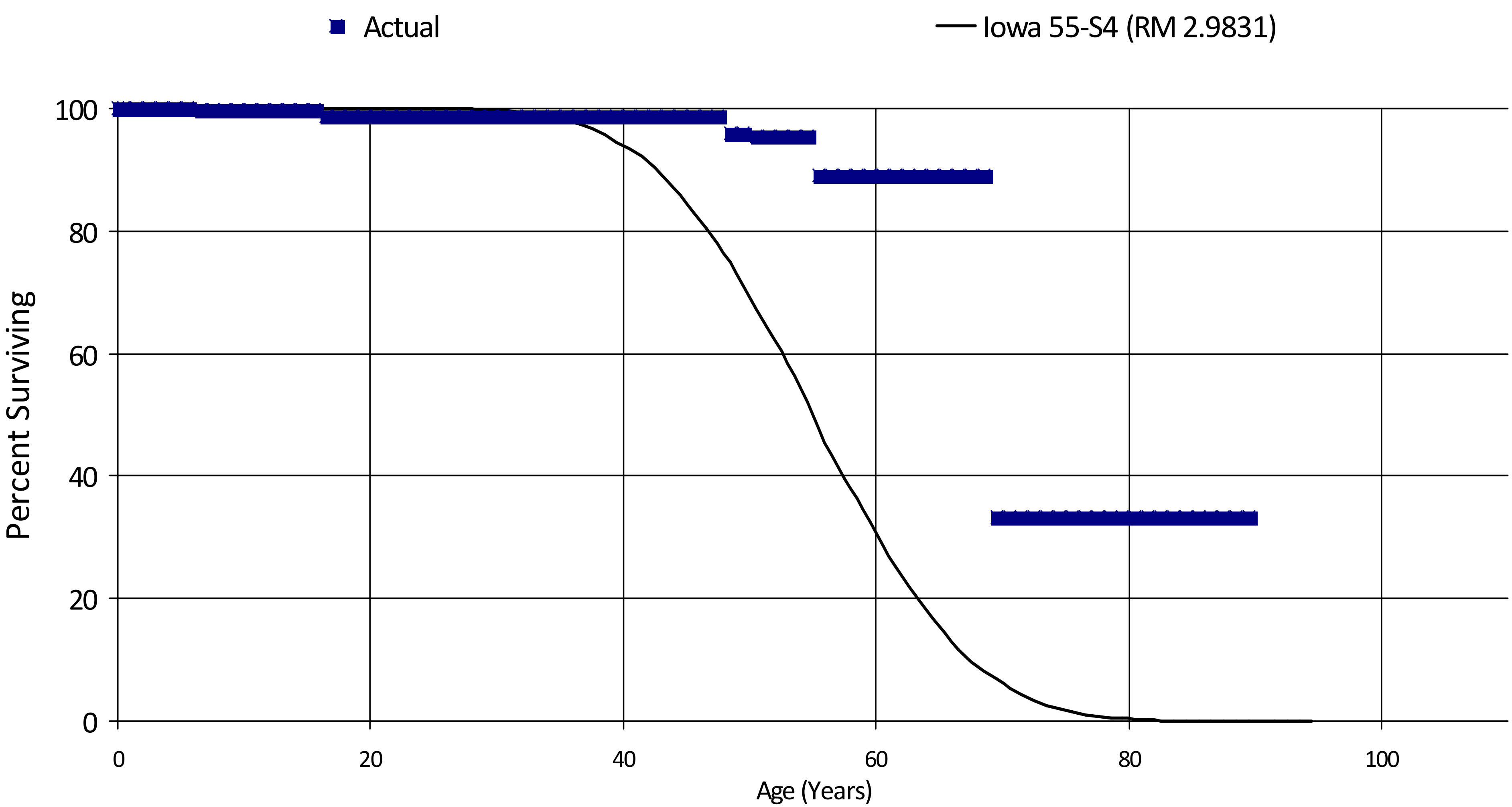
27.5	31,394,120	0	0.00000	1.00000	98.94
28.5	31,394,120	350,000	0.01115	0.98885	98.94
29.5	31,044,120	0	0.00000	1.00000	97.84
30.5	16,328,345	0	0.00000	1.00000	97.84
31.5	16,328,345	0	0.00000	1.00000	97.84
32.5	4,002,411	0	0.00000	1.00000	97.84
33.5	3,720,339	0	0.00000	1.00000	97.84
34.5	3,720,339	0	0.00000	1.00000	97.84
35.5	3,720,339	0	0.00000	1.00000	97.84
36.5	3,720,339	0	0.00000	1.00000	97.84
37.5	3,720,339	0	0.00000	1.00000	97.84
38.5	3,720,339	0	0.00000	1.00000	97.84
39.5	3,720,339	22,375	0.00601	0.99399	97.84
40.5	3,697,964	0	0.00000	1.00000	97.25
41.5	3,697,964	4,912	0.00133	0.99867	97.25
42.5	3,693,052	0	0.00000	1.00000	97.12
43.5	3,693,052	1,327,753	0.35953	0.64047	97.12
44.5	2,365,299	0	0.00000	1.00000	62.20
45.5	2,365,299	0	0.00000	1.00000	62.20
46.5	2,365,299	0	0.00000	1.00000	62.20
47.5	2,365,299	0	0.00000	1.00000	62.20
48.5	1,974,209	0	0.00000	1.00000	62.20
	Totals:	2,139,358			

Enbridge Gas Inc.

Account 463.00 - Transmssion Plant - Measuring and Regulating Structures and Improvements

Placement Band - 1931 - 2021 Experience Band - 2012 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 463.00 - Transmssion Plant - Measuring and Regulating Structures and Improvements

Placement Band - 1931 - 2021   Experience Band - 2012 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	11,454,695	0	0.00000	1.00000	100.00
0.5	10,669,212	0	0.00000	1.00000	100.00
1.5	10,669,212	0	0.00000	1.00000	100.00
2.5	10,457,144	0	0.00000	1.00000	100.00
3.5	10,408,231	0	0.00000	1.00000	100.00
4.5	10,353,901	0	0.00000	1.00000	100.00
5.5	10,143,769	14,845	0.00146	0.99854	100.00
6.5	10,128,924	0	0.00000	1.00000	99.85
7.5	10,112,314	0	0.00000	1.00000	99.85
8.5	10,109,314	0	0.00000	1.00000	99.85
9.5	9,905,643	0	0.00000	1.00000	99.85
10.5	9,821,474	0	0.00000	1.00000	99.85
11.5	9,800,615	0	0.00000	1.00000	99.85
12.5	9,792,468	0	0.00000	1.00000	99.85
13.5	9,359,979	0	0.00000	1.00000	99.85
14.5	9,087,104	0	0.00000	1.00000	99.85
15.5	8,924,294	96,606	0.01083	0.98917	99.85
16.5	8,702,160	0	0.00000	1.00000	98.77
17.5	8,702,160	0	0.00000	1.00000	98.77
18.5	8,702,160	0	0.00000	1.00000	98.77
19.5	8,412,649	0	0.00000	1.00000	98.77
20.5	8,412,649	0	0.00000	1.00000	98.77
21.5	8,363,198	0	0.00000	1.00000	98.77
22.5	8,357,813	0	0.00000	1.00000	98.77
23.5	8,253,754	0	0.00000	1.00000	98.77
24.5	8,206,276	0	0.00000	1.00000	98.77
25.5	8,206,276	0	0.00000	1.00000	98.77
26.5	7,279,698	0	0.00000	1.00000	98.77

Enbridge Gas Inc.

Account 463.00 - Transmssion Plant - Measuring and Regulating Structures and Improvements

Placement Band - 1931 - 2021 Experience Band - 2012 - 2021

27.5	7,182,278	0	0.00000	1.00000	98.77
28.5	6,468,446	0	0.00000	1.00000	98.77
29.5	6,130,609	0	0.00000	1.00000	98.77
30.5	5,134,579	0	0.00000	1.00000	98.77
31.5	4,348,860	0	0.00000	1.00000	98.77
32.5	3,557,581	0	0.00000	1.00000	98.77
33.5	3,534,742	0	0.00000	1.00000	98.77
34.5	2,693,320	0	0.00000	1.00000	98.77
35.5	2,065,465	0	0.00000	1.00000	98.77
36.5	2,041,700	0	0.00000	1.00000	98.77
37.5	1,812,164	0	0.00000	1.00000	98.77
38.5	1,766,921	0	0.00000	1.00000	98.77
39.5	1,620,122	0	0.00000	1.00000	98.77
40.5	1,381,522	0	0.00000	1.00000	98.77
41.5	1,381,522	0	0.00000	1.00000	98.77
42.5	1,281,885	421	0.00033	0.99967	98.77
43.5	1,200,652	0	0.00000	1.00000	98.74
44.5	1,111,793	546	0.00049	0.99951	98.74
45.5	1,098,453	0	0.00000	1.00000	98.69
46.5	1,043,050	456	0.00044	0.99956	98.69
47.5	946,529	26,062	0.02753	0.97247	98.65
48.5	912,771	0	0.00000	1.00000	95.93
49.5	908,244	3,824	0.00421	0.99579	95.93
50.5	892,356	0	0.00000	1.00000	95.53
51.5	888,989	0	0.00000	1.00000	95.53
52.5	877,550	1,875	0.00214	0.99786	95.53
53.5	859,415	0	0.00000	1.00000	95.33
54.5	859,415	56,795	0.06609	0.93391	95.33
55.5	789,730	0	0.00000	1.00000	89.03
56.5	676,263	0	0.00000	1.00000	89.03
57.5	593,393	0	0.00000	1.00000	89.03

Enbridge Gas Inc.

Account 463.00 - Transmssion Plant - Measuring and Regulating Structures and Improvements

Placement Band - 1931 - 2021 Experience Band - 2012 - 2021

58.5	587,913	0	0.00000	1.00000	89.03
59.5	568,497	0	0.00000	1.00000	89.03
60.5	499,573	0	0.00000	1.00000	89.03
61.5	328,691	0	0.00000	1.00000	89.03
62.5	324,807	0	0.00000	1.00000	89.03
63.5	2,392	0	0.00000	1.00000	89.03
64.5	2,392	0	0.00000	1.00000	89.03
65.5	2,392	0	0.00000	1.00000	89.03
66.5	2,392	0	0.00000	1.00000	89.03
67.5	1,566	0	0.00000	1.00000	89.03
68.5	1,566	983	0.62777	0.37223	89.03
69.5	583	0	0.00000	1.00000	33.14
70.5	583	0	0.00000	1.00000	33.14
71.5	583	0	0.00000	1.00000	33.14
72.5	583	0	0.00000	1.00000	33.14
73.5	583	0	0.00000	1.00000	33.14
74.5	583	0	0.00000	1.00000	33.14
75.5	583	0	0.00000	1.00000	33.14
76.5	583	0	0.00000	1.00000	33.14
77.5	583	0	0.00000	1.00000	33.14
78.5	583	0	0.00000	1.00000	33.14
79.5	583	0	0.00000	1.00000	33.14
80.5	583	0	0.00000	1.00000	33.14
81.5	583	0	0.00000	1.00000	33.14
82.5	583	0	0.00000	1.00000	33.14
83.5	583	0	0.00000	1.00000	33.14
84.5	583	0	0.00000	1.00000	33.14
85.5	583	0	0.00000	1.00000	33.14
86.5	583	0	0.00000	1.00000	33.14
87.5	583	0	0.00000	1.00000	33.14
88.5	583	0	0.00000	1.00000	33.14

Enbridge Gas Inc.

Account 463.00 - Transmssion Plant - Measuring and Regulating Structures and Improvements

Placement Band - 1931 - 2021 Experience Band - 2012 - 2021

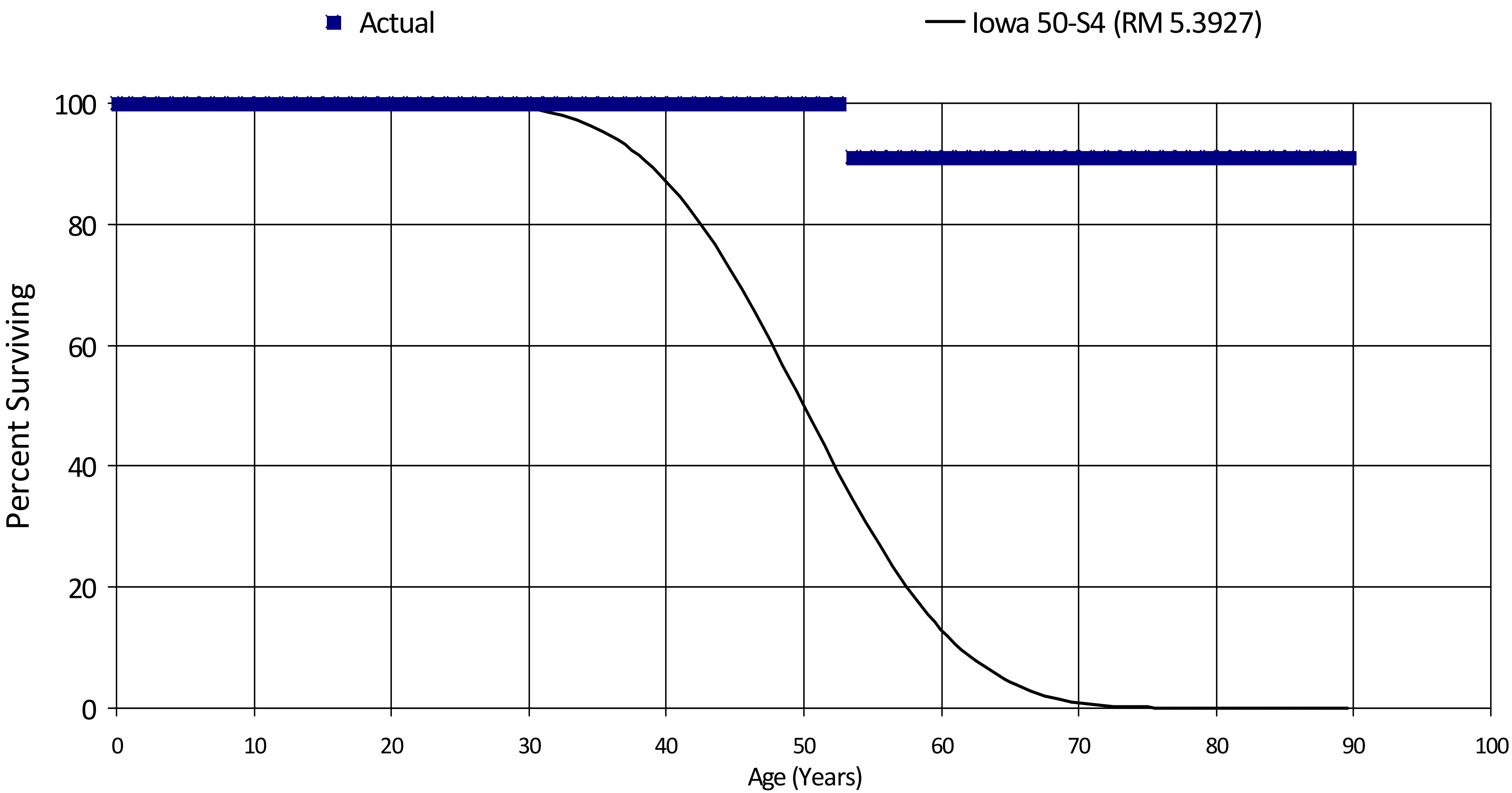
89.5	583	0	0.00000	1.00000	33.14
	Totals:	202,413			

Enbridge Gas Inc.

Account 464.00 - Transmission Plant - Equipment

Placement Band - 1931 - 2021 Experience Band - 2012 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 464.00 - Transmission Plant - Equipment

Placement Band - 1931 - 2021   Experience Band - 2012 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,929,879	0	0.00000	1.00000	100.00
0.5	2,758,012	0	0.00000	1.00000	100.00
1.5	2,758,012	0	0.00000	1.00000	100.00
2.5	1,830,024	0	0.00000	1.00000	100.00
3.5	1,830,024	0	0.00000	1.00000	100.00
4.5	1,827,417	0	0.00000	1.00000	100.00
5.5	511,104	0	0.00000	1.00000	100.00
6.5	511,104	0	0.00000	1.00000	100.00
7.5	502,076	0	0.00000	1.00000	100.00
8.5	502,076	0	0.00000	1.00000	100.00
9.5	502,076	0	0.00000	1.00000	100.00
10.5	502,076	0	0.00000	1.00000	100.00
11.5	502,076	0	0.00000	1.00000	100.00
12.5	502,076	0	0.00000	1.00000	100.00
13.5	502,076	0	0.00000	1.00000	100.00
14.5	502,076	0	0.00000	1.00000	100.00
15.5	502,076	0	0.00000	1.00000	100.00
16.5	502,076	0	0.00000	1.00000	100.00
17.5	502,076	0	0.00000	1.00000	100.00
18.5	502,076	0	0.00000	1.00000	100.00
19.5	502,076	0	0.00000	1.00000	100.00
20.5	502,076	0	0.00000	1.00000	100.00
21.5	502,076	0	0.00000	1.00000	100.00
22.5	502,076	0	0.00000	1.00000	100.00
23.5	502,076	0	0.00000	1.00000	100.00
24.5	502,076	0	0.00000	1.00000	100.00
25.5	378,895	0	0.00000	1.00000	100.00
26.5	302,362	0	0.00000	1.00000	100.00

Enbridge Gas Inc.

Account 464.00 - Transmission Plant - Equipment

Placement Band - 1931 - 2021   Experience Band - 2012 - 2021

27.5	287,747	0	0.00000	1.00000	100.00
28.5	287,747	0	0.00000	1.00000	100.00
29.5	242,676	0	0.00000	1.00000	100.00
30.5	213,333	0	0.00000	1.00000	100.00
31.5	213,333	0	0.00000	1.00000	100.00
32.5	196,257	0	0.00000	1.00000	100.00
33.5	178,500	0	0.00000	1.00000	100.00
34.5	122,714	0	0.00000	1.00000	100.00
35.5	122,714	0	0.00000	1.00000	100.00
36.5	122,714	0	0.00000	1.00000	100.00
37.5	122,714	0	0.00000	1.00000	100.00
38.5	122,714	0	0.00000	1.00000	100.00
39.5	122,714	0	0.00000	1.00000	100.00
40.5	114,913	0	0.00000	1.00000	100.00
41.5	114,913	0	0.00000	1.00000	100.00
42.5	114,913	0	0.00000	1.00000	100.00
43.5	114,913	0	0.00000	1.00000	100.00
44.5	114,913	0	0.00000	1.00000	100.00
45.5	114,913	0	0.00000	1.00000	100.00
46.5	109,810	0	0.00000	1.00000	100.00
47.5	109,810	0	0.00000	1.00000	100.00
48.5	109,810	0	0.00000	1.00000	100.00
49.5	109,810	0	0.00000	1.00000	100.00
50.5	109,810	0	0.00000	1.00000	100.00
51.5	108,552	0	0.00000	1.00000	100.00
52.5	107,262	9,662	0.09008	0.90992	100.00
53.5	97,600	0	0.00000	1.00000	90.99
54.5	81,242	0	0.00000	1.00000	90.99
55.5	81,242	0	0.00000	1.00000	90.99
56.5	81,242	0	0.00000	1.00000	90.99
57.5	81,242	0	0.00000	1.00000	90.99

Enbridge Gas Inc.

Account 464.00 - Transmission Plant - Equipment

Placement Band - 1931 - 2021 Experience Band - 2012 - 2021

58.5	74,554	0	0.00000	1.00000	90.99
59.5	65,892	0	0.00000	1.00000	90.99
60.5	15,996	0	0.00000	1.00000	90.99
61.5	9,018	0	0.00000	1.00000	90.99
62.5	9,018	0	0.00000	1.00000	90.99
63.5	9,018	0	0.00000	1.00000	90.99
64.5	9,018	0	0.00000	1.00000	90.99
65.5	9,018	0	0.00000	1.00000	90.99
66.5	8,913	0	0.00000	1.00000	90.99
67.5	8,095	0	0.00000	1.00000	90.99
68.5	2,862	0	0.00000	1.00000	90.99
69.5	1,970	0	0.00000	1.00000	90.99
70.5	1,970	0	0.00000	1.00000	90.99
71.5	1,380	0	0.00000	1.00000	90.99
72.5	1,380	0	0.00000	1.00000	90.99
73.5	699	0	0.00000	1.00000	90.99
74.5	699	0	0.00000	1.00000	90.99
75.5	699	0	0.00000	1.00000	90.99
76.5	699	0	0.00000	1.00000	90.99
77.5	699	0	0.00000	1.00000	90.99
78.5	699	0	0.00000	1.00000	90.99
79.5	699	0	0.00000	1.00000	90.99
80.5	699	0	0.00000	1.00000	90.99
81.5	699	0	0.00000	1.00000	90.99
82.5	699	0	0.00000	1.00000	90.99
83.5	699	0	0.00000	1.00000	90.99
84.5	699	0	0.00000	1.00000	90.99
85.5	699	0	0.00000	1.00000	90.99
86.5	699	0	0.00000	1.00000	90.99
87.5	699	0	0.00000	1.00000	90.99
88.5	699	0	0.00000	1.00000	90.99

Enbridge Gas Inc.

Account 464.00 - Transmission Plant - Equipment

Placement Band - 1931 - 2021 Experience Band - 2012 - 2021

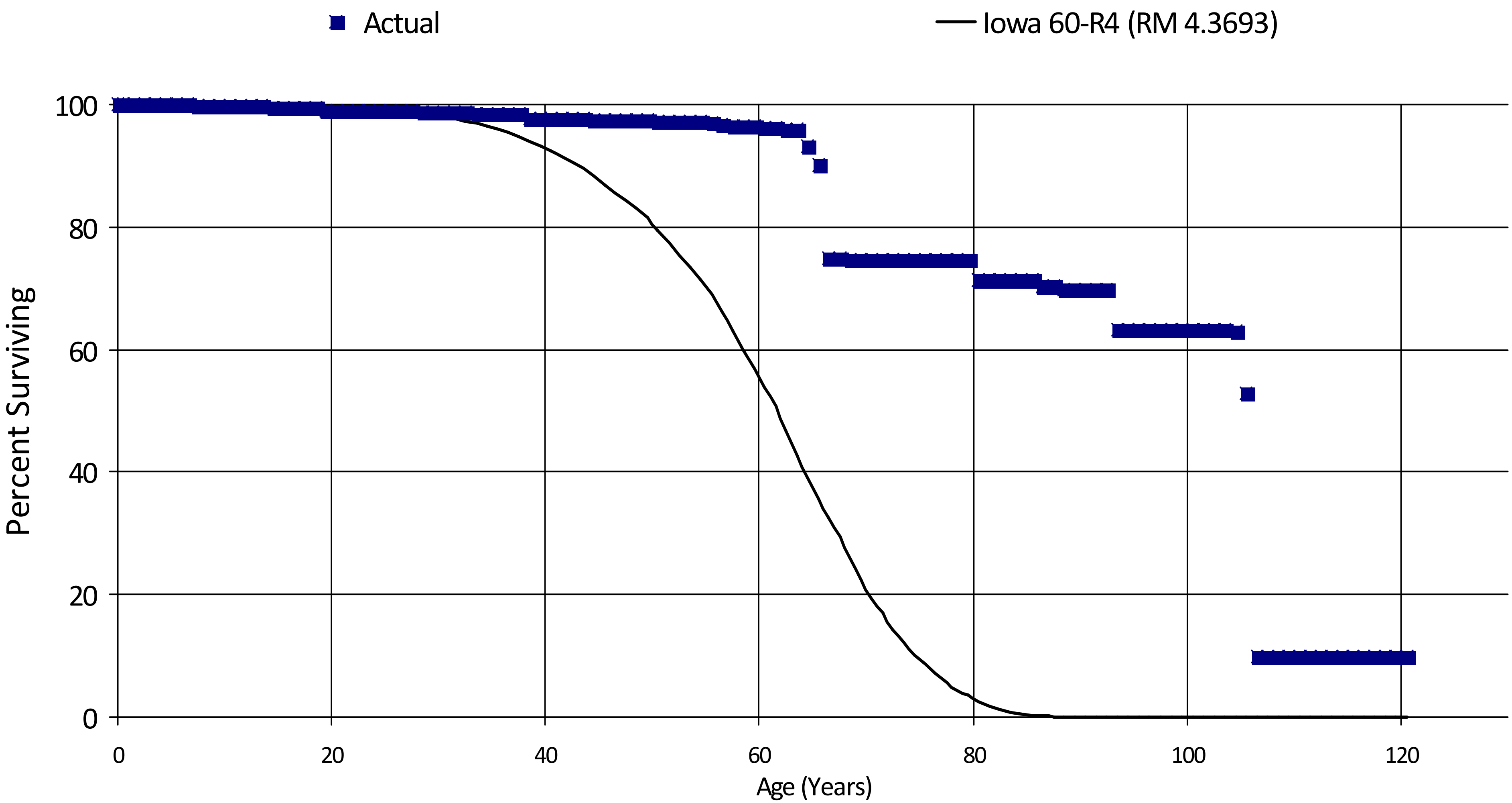
89.5	699	0	0.00000	1.00000	90.99
	Totals:	9,662			

Enbridge Gas Inc.

Account 465.00 - Transmission Plant - Mains

Placement Band - 1900 - 2021   Experience Band - 2010 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 465.00 - Transmission Plant - Mains

Placement Band - 1900 - 2021   Experience Band - 2010 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,803,741,089	0	0.00000	1.00000	100.00
0.5	2,613,843,841	0	0.00000	1.00000	100.00
1.5	2,540,021,396	226,979	0.00009	0.99991	100.00
2.5	2,440,634,563	85,660	0.00004	0.99996	99.99
3.5	2,424,753,044	2,075,444	0.00086	0.99914	99.99
4.5	2,221,919,486	390,907	0.00018	0.99982	99.90
5.5	1,550,516,263	36,472	0.00002	0.99998	99.88
6.5	1,393,690,109	1,358,450	0.00097	0.99903	99.88
7.5	1,350,917,098	93,697	0.00007	0.99993	99.78
8.5	1,281,678,958	392,547	0.00031	0.99969	99.77
9.5	1,239,964,582	710,788	0.00057	0.99943	99.74
10.5	1,223,379,010	53,969	0.00004	0.99996	99.68
11.5	1,214,401,635	100,061	0.00008	0.99992	99.68
12.5	1,169,296,869	18,703	0.00002	0.99998	99.67
13.5	1,158,062,141	1,293,972	0.00112	0.99888	99.67
14.5	1,075,806,566	444,596	0.00041	0.99959	99.56
15.5	950,236,394	79,048	0.00008	0.99992	99.52
16.5	938,159,875	44,712	0.00005	0.99995	99.51
17.5	933,455,313	1,226,375	0.00131	0.99869	99.51
18.5	924,707,838	2,941,607	0.00318	0.99682	99.38
19.5	869,843,993	122,639	0.00014	0.99986	99.06
20.5	823,255,104	178,204	0.00022	0.99978	99.05
21.5	805,399,240	51,721	0.00006	0.99994	99.03
22.5	751,431,049	58,169	0.00008	0.99992	99.02
23.5	717,146,602	231,147	0.00032	0.99968	99.01
24.5	697,210,518	554,323	0.00080	0.99920	98.98
25.5	645,097,421	41,464	0.00006	0.99994	98.90
26.5	615,018,447	98,222	0.00016	0.99984	98.89

Enbridge Gas Inc.

Account 465.00 - Transmission Plant - Mains

Placement Band - 1900 - 2021   Experience Band - 2010 - 2021

27.5	580,363,647	113,206	0.00020	0.99980	98.87
28.5	545,148,426	99,472	0.00018	0.99982	98.85
29.5	475,882,325	2,223	0.00000	1.00000	98.83
30.5	441,934,641	276,789	0.00063	0.99937	98.83
31.5	406,429,918	117,443	0.00029	0.99971	98.77
32.5	341,747,129	552,134	0.00162	0.99838	98.74
33.5	307,354,507	21,105	0.00007	0.99993	98.58
34.5	300,952,214	3,034	0.00001	0.99999	98.57
35.5	290,593,550	19,219	0.00007	0.99993	98.57
36.5	250,255,294	5,365	0.00002	0.99998	98.56
37.5	231,840,518	1,935,551	0.00835	0.99165	98.56
38.5	229,319,358	289,249	0.00126	0.99874	97.74
39.5	197,293,755	5,267	0.00003	0.99997	97.62
40.5	178,035,054	12,968	0.00007	0.99993	97.62
41.5	175,658,698	4,204	0.00002	0.99998	97.61
42.5	164,608,852	2,811	0.00002	0.99998	97.61
43.5	160,955,902	74,545	0.00046	0.99954	97.61
44.5	159,775,717	257,008	0.00161	0.99839	97.57
45.5	155,064,747	5,590	0.00004	0.99996	97.41
46.5	128,164,459	73,066	0.00057	0.99943	97.41
47.5	123,389,698	10,244	0.00008	0.99992	97.35
48.5	120,792,162	2,181	0.00002	0.99998	97.34
49.5	107,827,092	11,524	0.00011	0.99989	97.34
50.5	98,546,828	21,636	0.00022	0.99978	97.33
51.5	91,909,623	158,177	0.00172	0.99828	97.31
52.5	89,811,974	13,580	0.00015	0.99985	97.14
53.5	86,440,168	136	0.00000	1.00000	97.13
54.5	77,336,390	40,616	0.00053	0.99947	97.13
55.5	71,213,266	279,031	0.00392	0.99608	97.08
56.5	65,376,068	172,283	0.00264	0.99736	96.70
57.5	54,534,905	34,436	0.00063	0.99937	96.44

Enbridge Gas Inc.

Account 465.00 - Transmission Plant - Mains

Placement Band - 1900 - 2021 Experience Band - 2010 - 2021

58.5	53,593,141	10,019	0.00019	0.99981	96.38
59.5	51,487,181	86,887	0.00169	0.99831	96.36
60.5	50,557,758	14,449	0.00029	0.99971	96.20
61.5	49,569,661	98,285	0.00198	0.99802	96.17
62.5	46,301,311	4,876	0.00011	0.99989	95.98
63.5	26,886,159	813,083	0.03024	0.96976	95.97
64.5	8,783,639	279,028	0.03177	0.96823	93.07
65.5	8,383,224	1,421,417	0.16955	0.83045	90.11
66.5	6,290,918	0	0.00000	1.00000	74.83
67.5	6,122,925	11,259	0.00184	0.99816	74.83
68.5	5,042,720	462	0.00009	0.99991	74.69
69.5	5,030,586	792	0.00016	0.99984	74.68
70.5	3,845,644	336	0.00009	0.99991	74.67
71.5	3,795,313	5,990	0.00158	0.99842	74.66
72.5	3,789,323	0	0.00000	1.00000	74.54
73.5	3,787,465	169	0.00004	0.99996	74.54
74.5	3,147,363	59	0.00002	0.99998	74.54
75.5	2,839,551	0	0.00000	1.00000	74.54
76.5	2,772,150	1,677	0.00060	0.99940	74.54
77.5	2,770,473	0	0.00000	1.00000	74.50
78.5	2,707,073	119	0.00004	0.99996	74.50
79.5	2,475,679	105,467	0.04260	0.95740	74.50
80.5	2,110,549	400	0.00019	0.99981	71.33
81.5	1,944,029	0	0.00000	1.00000	71.32
82.5	1,804,657	28	0.00002	0.99998	71.32
83.5	1,653,889	0	0.00000	1.00000	71.32
84.5	1,245,577	1,578	0.00127	0.99873	71.32
85.5	492,269	7,187	0.01460	0.98540	71.23
86.5	484,957	37	0.00008	0.99992	70.19
87.5	484,920	2,604	0.00537	0.99463	70.18
88.5	482,316	0	0.00000	1.00000	69.80

Enbridge Gas Inc.

Account 465.00 - Transmission Plant - Mains

Placement Band - 1900 - 2021 Experience Band - 2010 - 2021

89.5	482,316	0	0.00000	1.00000	69.80
90.5	326,241	0	0.00000	1.00000	69.80
91.5	264,670	0	0.00000	1.00000	69.80
92.5	264,670	24,944	0.09425	0.90575	69.80
93.5	199,553	0	0.00000	1.00000	63.22
94.5	129,574	0	0.00000	1.00000	63.22
95.5	121,655	120	0.00099	0.99901	63.22
96.5	121,535	0	0.00000	1.00000	63.16
97.5	121,535	0	0.00000	1.00000	63.16
98.5	121,535	0	0.00000	1.00000	63.16
99.5	121,535	0	0.00000	1.00000	63.16
100.5	87,801	0	0.00000	1.00000	63.16
101.5	87,801	0	0.00000	1.00000	63.16
102.5	87,801	0	0.00000	1.00000	63.16
103.5	87,801	144	0.00164	0.99836	63.16
104.5	87,657	14,241	0.16246	0.83754	63.06
105.5	73,416	59,663	0.81267	0.18733	52.82
106.5	13,753	0	0.00000	1.00000	9.89
107.5	13,753	0	0.00000	1.00000	9.89
108.5	13,753	0	0.00000	1.00000	9.89
109.5	13,753	0	0.00000	1.00000	9.89
110.5	13,753	0	0.00000	1.00000	9.89
111.5	505	0	0.00000	1.00000	9.89
112.5	505	0	0.00000	1.00000	9.89
113.5	505	0	0.00000	1.00000	9.89
114.5	505	0	0.00000	1.00000	9.89
115.5	505	0	0.00000	1.00000	9.89
116.5	505	0	0.00000	1.00000	9.89
117.5	505	0	0.00000	1.00000	9.89
118.5	505	0	0.00000	1.00000	9.89
119.5	505	0	0.00000	1.00000	9.89

Enbridge Gas Inc.

Account 465.00 - Transmission Plant - Mains

Placement Band - 1900 - 2021 Experience Band - 2010 - 2021

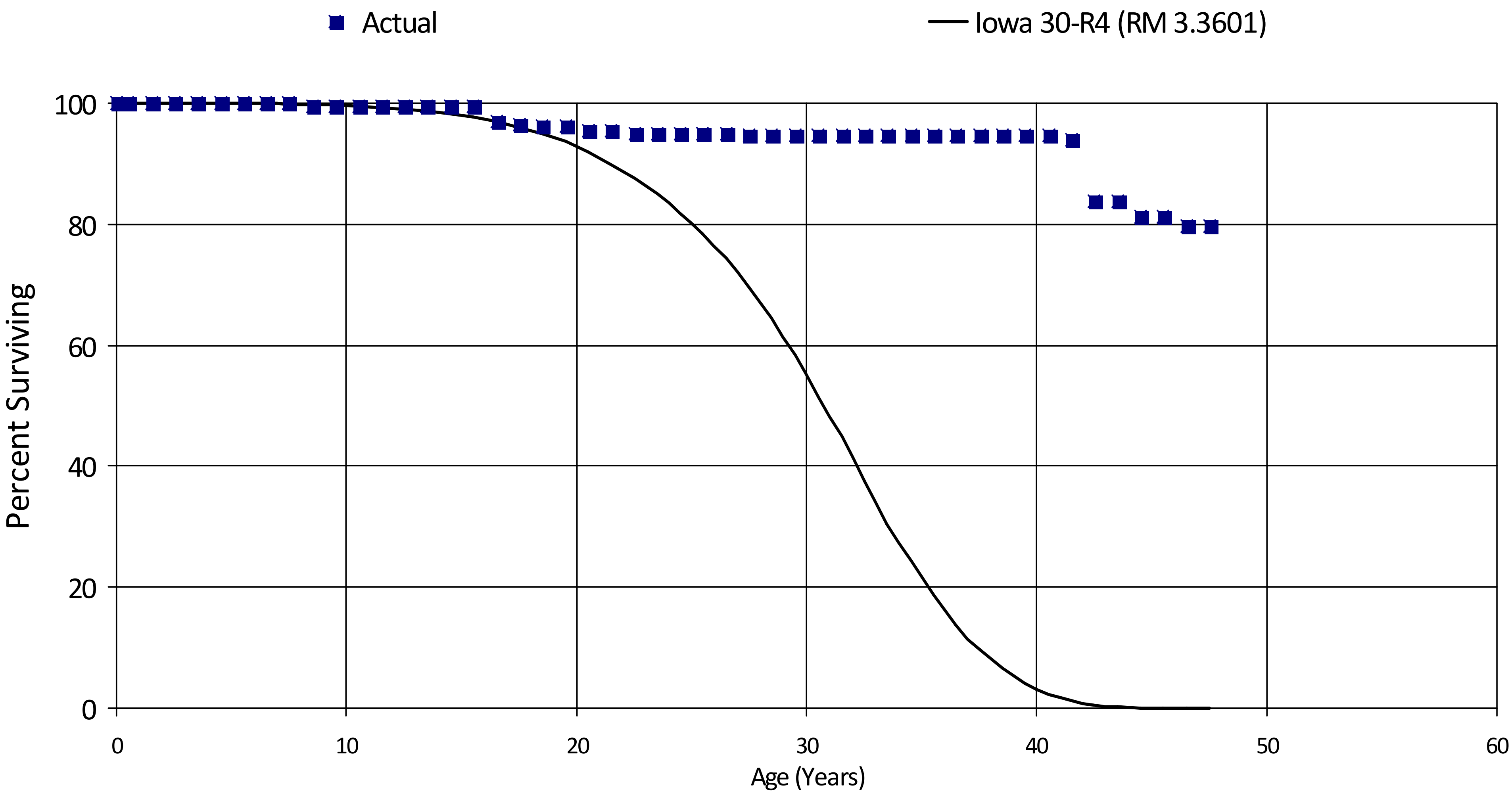
120.5	505	0	0.00000	1.00000	9.89
	Totals:	20,489,289			

Enbridge Gas Inc.

Account 466.00 - Transmission Plant - Compressor Equipment

Placement Band - 1900 - 2021 Experience Band - 2010 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 466.00 - Transmission Plant - Compressor Equipment

Placement Band - 1900 - 2021   Experience Band - 2010 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,014,971,579	0	0.00000	1.00000	100.00
0.5	952,609,404	0	0.00000	1.00000	100.00
1.5	950,851,528	0	0.00000	1.00000	100.00
2.5	950,231,397	0	0.00000	1.00000	100.00
3.5	947,843,208	0	0.00000	1.00000	100.00
4.5	712,197,050	0	0.00000	1.00000	100.00
5.5	559,096,544	0	0.00000	1.00000	100.00
6.5	355,635,168	0	0.00000	1.00000	100.00
7.5	349,109,663	1,432,718	0.00410	0.99590	100.00
8.5	345,727,392	0	0.00000	1.00000	99.59
9.5	312,359,155	0	0.00000	1.00000	99.59
10.5	295,173,640	0	0.00000	1.00000	99.59
11.5	289,417,618	0	0.00000	1.00000	99.59
12.5	287,439,582	0	0.00000	1.00000	99.59
13.5	207,258,498	0	0.00000	1.00000	99.59
14.5	126,219,385	61,532	0.00049	0.99951	99.59
15.5	119,817,945	3,151,799	0.02630	0.97370	99.54
16.5	116,666,146	609,978	0.00523	0.99477	96.92
17.5	114,948,115	203,337	0.00177	0.99823	96.41
18.5	114,744,778	100,000	0.00087	0.99913	96.24
19.5	114,644,778	915,862	0.00799	0.99201	96.16
20.5	111,491,288	0	0.00000	1.00000	95.39
21.5	111,491,288	537,959	0.00483	0.99517	95.39
22.5	110,953,329	0	0.00000	1.00000	94.93
23.5	110,953,329	14,546	0.00013	0.99987	94.93
24.5	110,938,783	0	0.00000	1.00000	94.92
25.5	69,579,763	0	0.00000	1.00000	94.92
26.5	58,504,789	199,097	0.00340	0.99660	94.92

Enbridge Gas Inc.

Account 466.00 - Transmission Plant - Compressor Equipment

Placement Band - 1900 - 2021   Experience Band - 2010 - 2021

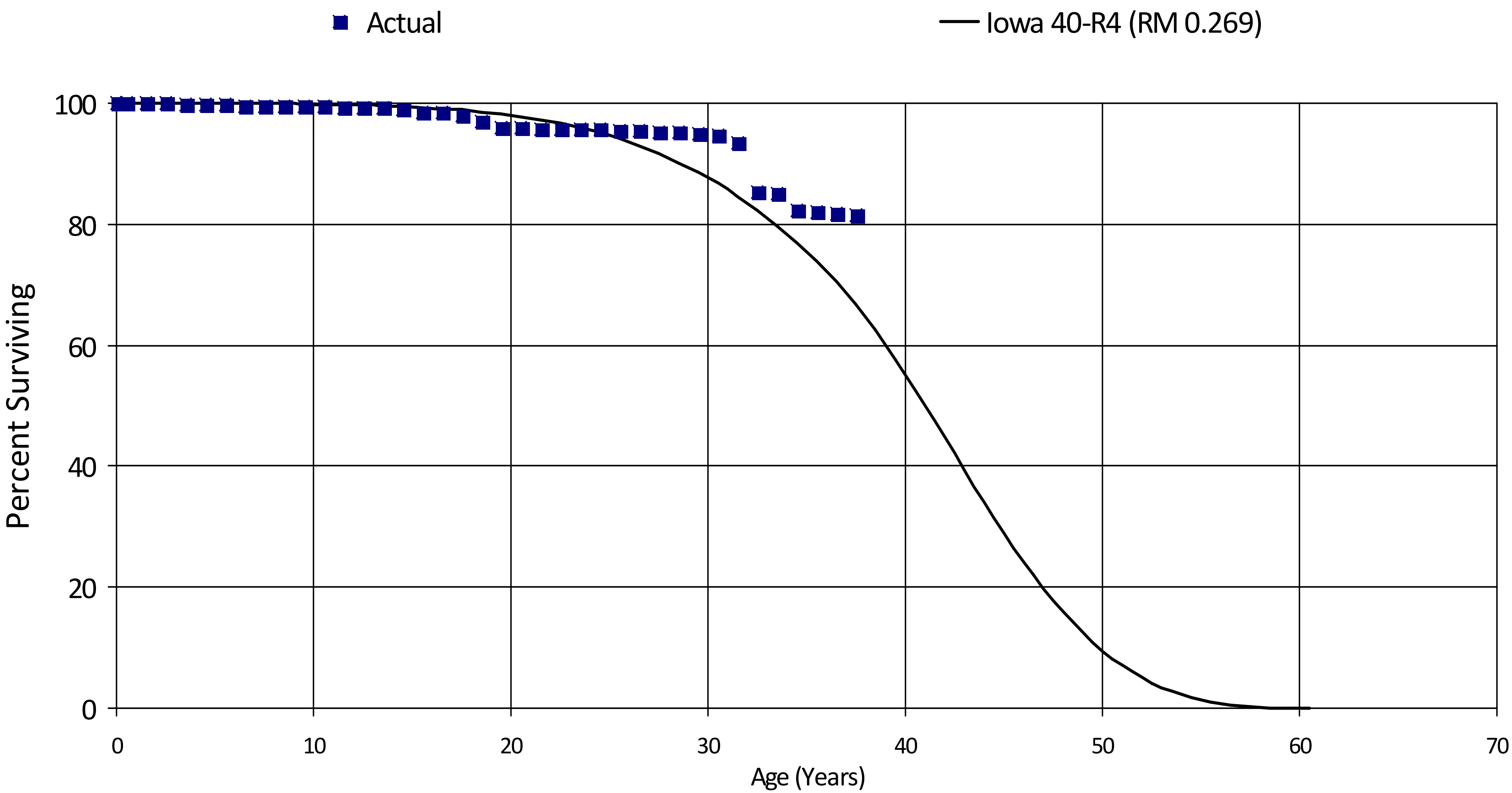
27.5	51,707,015	0	0.00000	1.00000	94.60
28.5	47,436,528	0	0.00000	1.00000	94.60
29.5	47,436,528	0	0.00000	1.00000	94.60
30.5	47,436,528	0	0.00000	1.00000	94.60
31.5	18,371,951	0	0.00000	1.00000	94.60
32.5	18,371,951	0	0.00000	1.00000	94.60
33.5	14,604,311	0	0.00000	1.00000	94.60
34.5	14,604,311	0	0.00000	1.00000	94.60
35.5	14,604,311	0	0.00000	1.00000	94.60
36.5	14,604,311	0	0.00000	1.00000	94.60
37.5	14,604,311	0	0.00000	1.00000	94.60
38.5	14,604,311	0	0.00000	1.00000	94.60
39.5	14,604,311	0	0.00000	1.00000	94.60
40.5	14,604,311	100,000	0.00685	0.99315	94.60
41.5	14,504,311	1,567,118	0.10804	0.89196	93.95
42.5	12,937,193	0	0.00000	1.00000	83.80
43.5	12,937,193	402,980	0.03115	0.96885	83.80
44.5	12,534,213	0	0.00000	1.00000	81.19
45.5	12,534,213	238,956	0.01906	0.98094	81.19
46.5	12,295,257	0	0.00000	1.00000	79.64
47.5	12,295,257	0	0.00000	1.00000	79.64
	Totals:	9,535,882			

Enbridge Gas Inc.

Account 467.00 - Transmission Plant - Measuring and Regulating Equipment

Placement Band - 1959 - 2021 Experience Band - 2010 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 467.00 - Transmission Plant - Measuring and Regulating Equipment

Placement Band - 1959 - 2021   Experience Band - 2010 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	402,784,001	32,717	0.00008	0.99992	100.00
0.5	360,518,617	217,899	0.00060	0.99940	99.99
1.5	334,705,980	88,607	0.00026	0.99974	99.93
2.5	308,119,813	187,395	0.00061	0.99939	99.90
3.5	294,272,988	0	0.00000	1.00000	99.84
4.5	243,617,036	478,127	0.00196	0.99804	99.84
5.5	210,904,775	69,733	0.00033	0.99967	99.64
6.5	180,865,632	22,939	0.00013	0.99987	99.61
7.5	156,092,389	31,079	0.00020	0.99980	99.60
8.5	150,187,549	166,779	0.00111	0.99889	99.58
9.5	142,264,686	84,385	0.00059	0.99941	99.47
10.5	134,713,682	122,652	0.00091	0.99909	99.41
11.5	130,145,933	104,376	0.00080	0.99920	99.32
12.5	123,432,645	58,727	0.00048	0.99952	99.24
13.5	117,178,399	144,993	0.00124	0.99876	99.19
14.5	112,052,948	778,313	0.00695	0.99305	99.07
15.5	107,739,013	0	0.00000	1.00000	98.38
16.5	102,142,614	358,364	0.00351	0.99649	98.38
17.5	101,367,998	1,049,105	0.01035	0.98965	98.03
18.5	98,968,368	1,027,377	0.01038	0.98962	97.02
19.5	94,734,617	13,995	0.00015	0.99985	96.01
20.5	94,407,801	211,033	0.00224	0.99776	96.00
21.5	90,805,100	65,501	0.00072	0.99928	95.78
22.5	89,331,946	32,355	0.00036	0.99964	95.71
23.5	87,698,871	62,720	0.00072	0.99928	95.68
24.5	84,606,627	154,267	0.00182	0.99818	95.61
25.5	75,164,415	94,992	0.00126	0.99874	95.44
26.5	47,549,755	62,678	0.00132	0.99868	95.32

Enbridge Gas Inc.

Account 467.00 - Transmission Plant - Measuring and Regulating Equipment

Placement Band - 1959 - 2021 Experience Band - 2010 - 2021

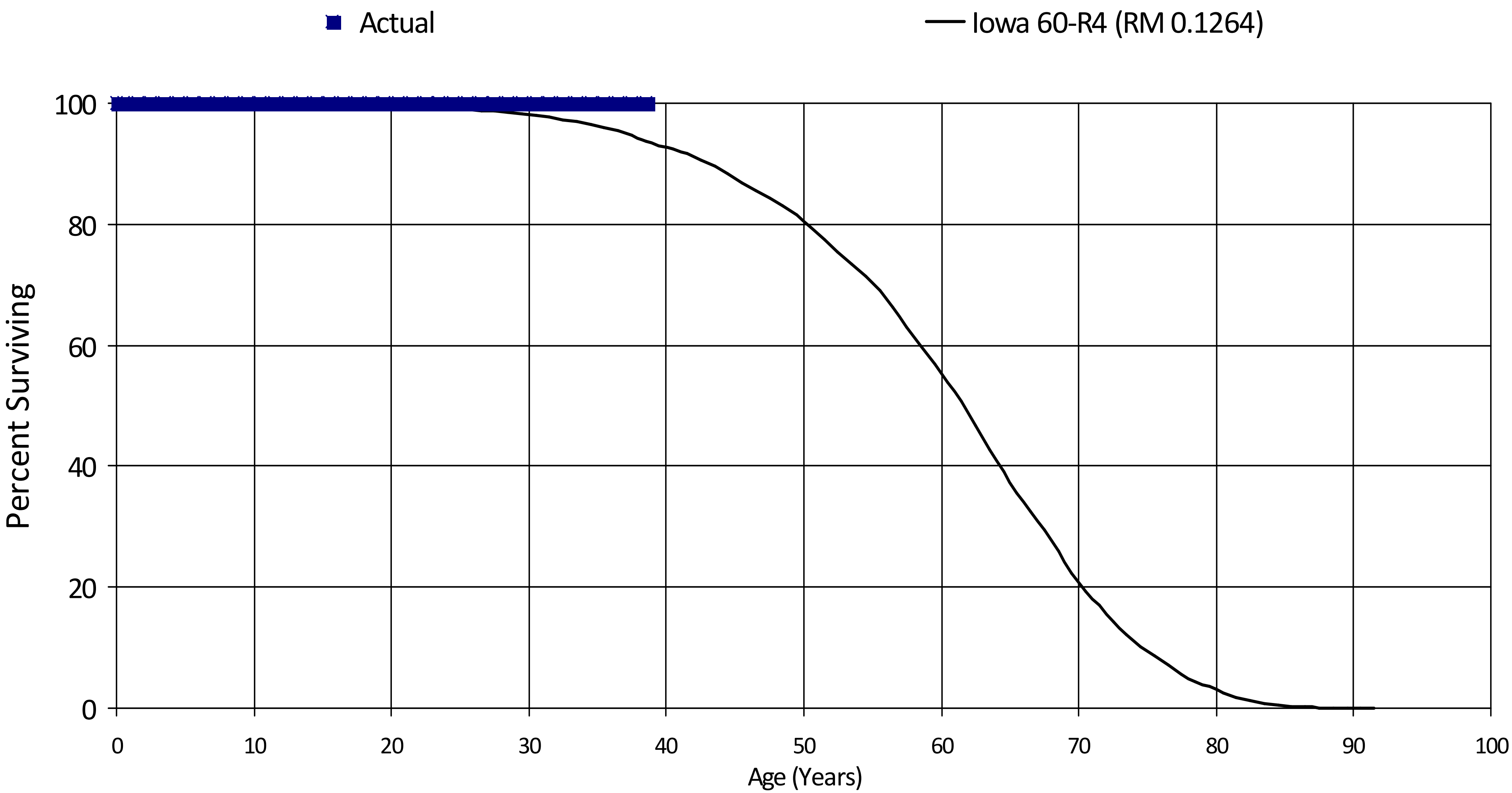
27.5	27,106,345	0	0.00000	1.00000	95.19
28.5	22,221,242	71,834	0.00323	0.99677	95.19
29.5	17,511,684	18,312	0.00105	0.99895	94.88
30.5	12,757,013	178,020	0.01395	0.98605	94.78
31.5	8,888,307	786,807	0.08852	0.91148	93.46
32.5	6,955,697	6,723	0.00097	0.99903	85.19
33.5	6,406,699	221,662	0.03460	0.96540	85.11
34.5	5,152,547	7,335	0.00142	0.99858	82.17
35.5	4,397,437	18,021	0.00410	0.99590	82.05
36.5	4,226,542	8,432	0.00200	0.99800	81.71
37.5	3,693,802	0	0.00000	1.00000	81.55
	Totals:	7,038,254			

Enbridge Gas Inc.

Account 471.00 - Distribution - Land Rights

Placement Band - 1982 - 2021   Experience Band - 2021 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 471.00 - Distribution - Land Rights

Placement Band - 1982 - 2021 Experience Band - 2021 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	63,907,560	0	0.00000	1.00000	100.00
0.5	63,592,865	0	0.00000	1.00000	100.00
1.5	62,766,625	0	0.00000	1.00000	100.00
2.5	62,154,813	0	0.00000	1.00000	100.00
3.5	61,655,034	0	0.00000	1.00000	100.00
4.5	61,300,956	0	0.00000	1.00000	100.00
5.5	28,103,465	0	0.00000	1.00000	100.00
6.5	27,627,350	0	0.00000	1.00000	100.00
7.5	23,141,338	0	0.00000	1.00000	100.00
8.5	22,599,773	0	0.00000	1.00000	100.00
9.5	22,200,202	0	0.00000	1.00000	100.00
10.5	21,947,213	0	0.00000	1.00000	100.00
11.5	21,716,944	0	0.00000	1.00000	100.00
12.5	21,217,644	0	0.00000	1.00000	100.00
13.5	13,264,476	0	0.00000	1.00000	100.00
14.5	13,030,779	0	0.00000	1.00000	100.00
15.5	12,827,099	0	0.00000	1.00000	100.00
16.5	12,630,521	0	0.00000	1.00000	100.00
17.5	12,544,730	0	0.00000	1.00000	100.00
18.5	12,422,171	0	0.00000	1.00000	100.00
19.5	12,239,034	0	0.00000	1.00000	100.00
20.5	12,113,598	0	0.00000	1.00000	100.00
21.5	11,948,749	0	0.00000	1.00000	100.00
22.5	11,662,485	0	0.00000	1.00000	100.00
23.5	11,170,717	0	0.00000	1.00000	100.00
24.5	10,781,472	0	0.00000	1.00000	100.00
25.5	10,450,206	0	0.00000	1.00000	100.00
26.5	9,951,927	0	0.00000	1.00000	100.00

Enbridge Gas Inc.

Account 471.00 - Distribution - Land Rights

Placement Band - 1982 - 2021 Experience Band - 2021 - 2021

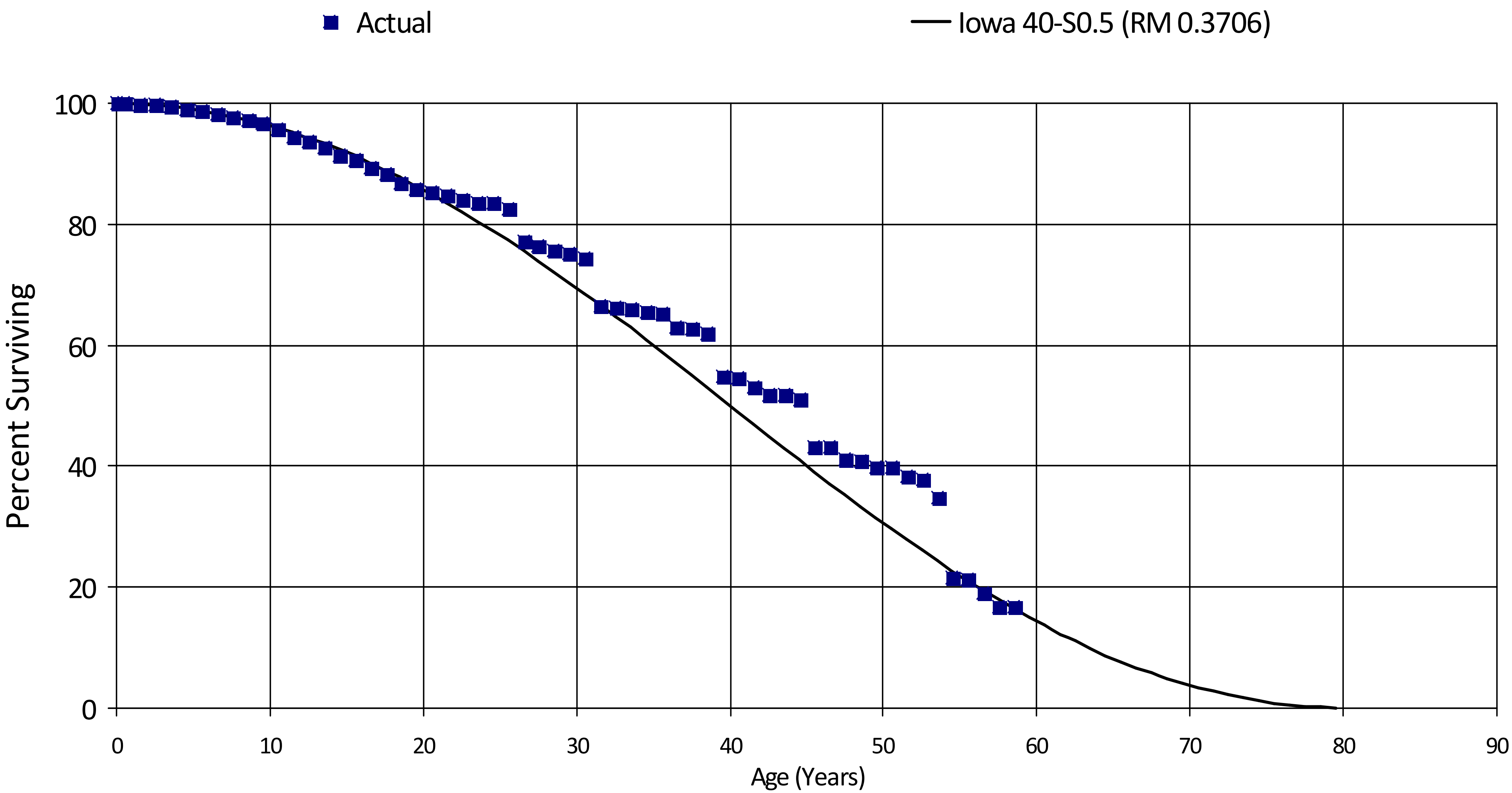
27.5	6,487,472	0	0.00000	1.00000	100.00
28.5	6,335,702	0	0.00000	1.00000	100.00
29.5	6,227,393	0	0.00000	1.00000	100.00
30.5	6,111,592	0	0.00000	1.00000	100.00
31.5	5,877,975	0	0.00000	1.00000	100.00
32.5	5,820,415	0	0.00000	1.00000	100.00
33.5	5,719,736	0	0.00000	1.00000	100.00
34.5	5,365,306	0	0.00000	1.00000	100.00
35.5	4,407,258	0	0.00000	1.00000	100.00
36.5	980,920	0	0.00000	1.00000	100.00
37.5	807,154	0	0.00000	1.00000	100.00
38.5	734,045	0	0.00000	1.00000	100.00
	Totals:	0			

Enbridge Gas Inc.

Account 472.00 - Distribution - Structures and Improvements

Placement Band - 1928 - 2021 Experience Band - 1948 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 472.00 - Distribution - Structures and Improvements

Placement Band - 1928 - 2021   Experience Band - 1948 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	452,380,067	-472,909	-0.00105	1.00105	100.00
0.5	368,122,896	846,365	0.00230	0.99770	100.10
1.5	362,865,019	613,933	0.00169	0.99831	99.87
2.5	355,984,539	332,338	0.00093	0.99907	99.70
3.5	353,694,105	2,072,346	0.00586	0.99414	99.61
4.5	347,422,936	1,195,559	0.00344	0.99656	99.03
5.5	338,317,697	1,394,956	0.00412	0.99588	98.69
6.5	331,724,471	1,624,626	0.00490	0.99510	98.28
7.5	325,109,849	1,985,919	0.00611	0.99389	97.80
8.5	294,317,773	1,703,165	0.00579	0.99421	97.20
9.5	284,730,628	2,769,604	0.00973	0.99027	96.64
10.5	277,233,183	3,356,645	0.01211	0.98789	95.70
11.5	267,383,951	2,632,293	0.00984	0.99016	94.54
12.5	224,193,174	2,601,430	0.01160	0.98840	93.61
13.5	204,740,531	2,427,486	0.01186	0.98814	92.52
14.5	197,001,231	1,904,500	0.00967	0.99033	91.42
15.5	190,326,176	2,455,938	0.01290	0.98710	90.54
16.5	187,361,518	2,173,674	0.01160	0.98840	89.37
17.5	183,254,232	3,048,665	0.01664	0.98336	88.33
18.5	178,179,918	2,111,512	0.01185	0.98815	86.86
19.5	171,778,631	1,259,104	0.00733	0.99267	85.83
20.5	170,315,919	932,042	0.00547	0.99453	85.20
21.5	168,932,527	1,508,777	0.00893	0.99107	84.73
22.5	166,655,879	816,941	0.00490	0.99510	83.97
23.5	164,927,495	343,954	0.00209	0.99791	83.56
24.5	156,102,513	1,619,446	0.01037	0.98963	83.39
25.5	152,867,791	10,084,746	0.06597	0.93403	82.53
26.5	130,821,834	1,339,906	0.01024	0.98976	77.09

Enbridge Gas Inc.

Account 472.00 - Distribution - Structures and Improvements

Placement Band - 1928 - 2021 Experience Band - 1948 - 2021

27.5	126,221,569	917,317	0.00727	0.99273	76.30
28.5	124,597,405	1,040,665	0.00835	0.99165	75.75
29.5	121,809,488	1,322,718	0.01086	0.98914	75.12
30.5	118,693,613	12,465,209	0.10502	0.89498	74.30
31.5	105,700,978	432,455	0.00409	0.99591	66.50
32.5	103,949,467	400,681	0.00385	0.99615	66.23
33.5	102,827,367	665,935	0.00648	0.99352	65.98
34.5	101,441,005	583,011	0.00575	0.99425	65.55
35.5	100,539,221	3,413,074	0.03395	0.96605	65.17
36.5	95,750,433	418,494	0.00437	0.99563	62.96
37.5	95,074,624	1,268,426	0.01334	0.98666	62.68
38.5	92,890,592	10,386,112	0.11181	0.88819	61.84
39.5	80,439,393	383,674	0.00477	0.99523	54.93
40.5	78,577,554	2,263,227	0.02880	0.97120	54.67
41.5	74,886,492	1,744,291	0.02329	0.97671	53.10
42.5	73,098,980	31,955	0.00044	0.99956	51.86
43.5	73,062,278	1,128,644	0.01545	0.98455	51.84
44.5	70,959,672	10,833,197	0.15267	0.84733	51.04
45.5	60,007,825	304,404	0.00507	0.99493	43.25
46.5	59,665,696	2,611,801	0.04377	0.95623	43.03
47.5	41,829,367	215,309	0.00515	0.99485	41.15
48.5	41,474,615	1,118,006	0.02696	0.97304	40.94
49.5	40,151,523	32,974	0.00082	0.99918	39.84
50.5	33,845,874	1,243,887	0.03675	0.96325	39.81
51.5	31,679,995	427,313	0.01349	0.98651	38.35
52.5	29,439,830	2,460,042	0.08356	0.91644	37.83
53.5	19,841,923	7,483,676	0.37716	0.62284	34.67
54.5	12,244,974	121,707	0.00994	0.99006	21.59
55.5	12,011,789	1,291,287	0.10750	0.89250	21.38
56.5	10,628,149	1,324,814	0.12465	0.87535	19.08
57.5	8,815,979	524	0.00006	0.99994	16.70

Enbridge Gas Inc.

Account 472.00 - Distribution - Structures and Improvements

Placement Band - 1928 - 2021 Experience Band - 1948 - 2021

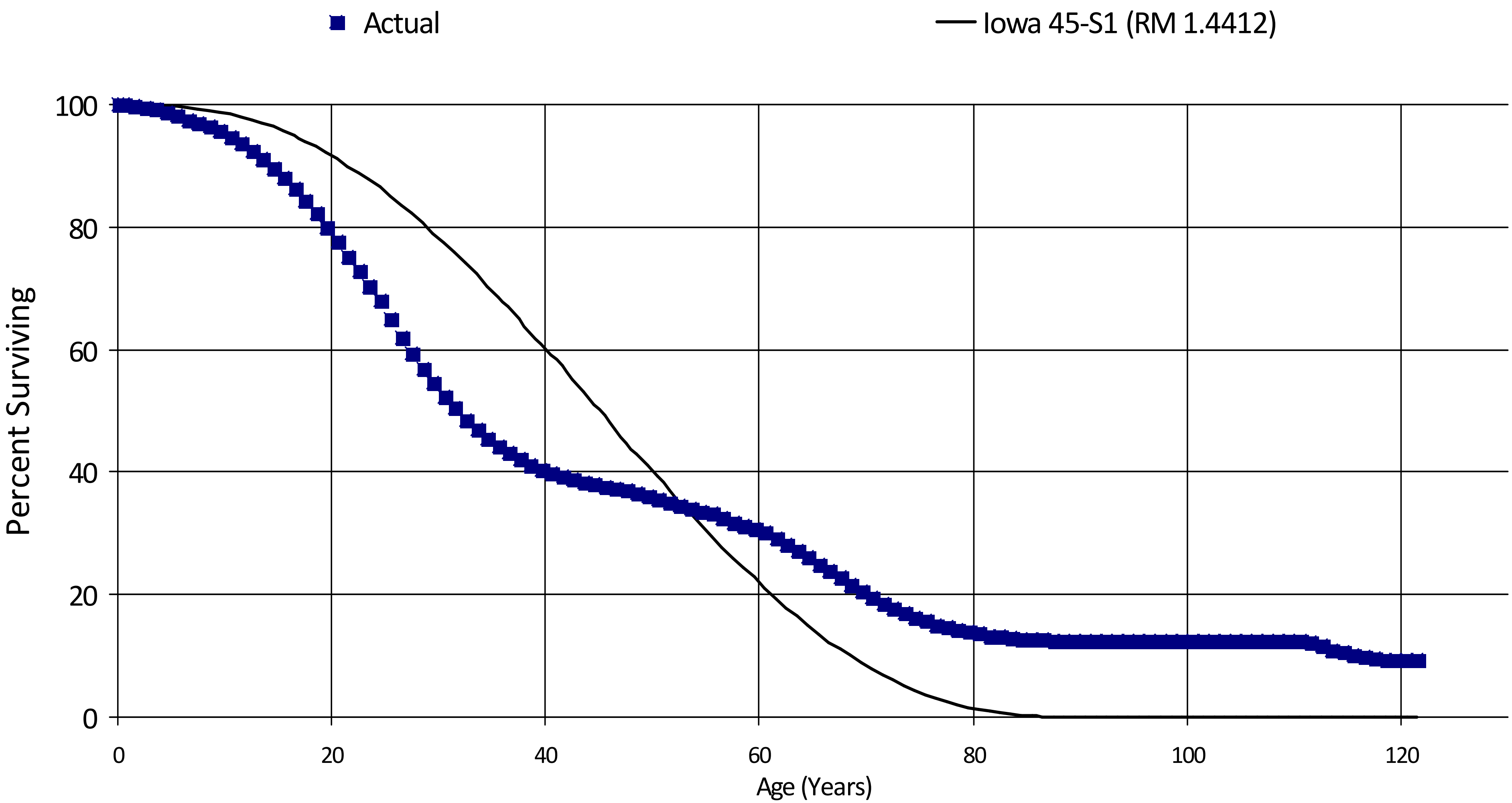
58.5	8,747,083	2,465,271	0.28184	0.71816	16.70
	Totals:	125,483,061			

Enbridge Gas Inc.

Account 473.01 - Distribution - Services - Metal

Placement Band - 1884 - 2021   Experience Band - 1956 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 473.01 - Distribution - Services - Metal

Placement Band - 1884 - 2021   Experience Band - 1956 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	962,637,166	527,581	0.00055	0.99945	100.00
0.5	849,884,886	1,281,405	0.00151	0.99849	99.94
1.5	835,901,505	1,829,425	0.00219	0.99781	99.79
2.5	820,383,536	3,742,647	0.00456	0.99544	99.57
3.5	806,297,735	3,905,759	0.00484	0.99516	99.12
4.5	791,005,065	4,163,156	0.00526	0.99474	98.64
5.5	776,684,101	4,373,339	0.00563	0.99437	98.12
6.5	758,900,133	4,660,206	0.00614	0.99386	97.57
7.5	739,819,057	4,496,343	0.00608	0.99392	96.97
8.5	720,434,677	5,681,940	0.00789	0.99211	96.38
9.5	702,441,556	6,699,733	0.00954	0.99046	95.62
10.5	689,210,961	8,410,216	0.01220	0.98780	94.71
11.5	672,721,820	8,600,676	0.01278	0.98722	93.55
12.5	660,315,521	8,898,877	0.01348	0.98652	92.35
13.5	643,456,027	9,809,957	0.01525	0.98475	91.11
14.5	623,620,473	11,100,331	0.01780	0.98220	89.72
15.5	601,663,629	12,591,924	0.02093	0.97907	88.12
16.5	579,007,759	13,257,955	0.02290	0.97710	86.28
17.5	561,181,428	14,024,635	0.02499	0.97501	84.30
18.5	541,857,715	14,910,063	0.02752	0.97248	82.19
19.5	521,014,446	15,191,739	0.02916	0.97084	79.93
20.5	500,181,922	15,199,426	0.03039	0.96961	77.60
21.5	480,584,644	15,258,788	0.03175	0.96825	75.24
22.5	460,289,809	15,567,951	0.03382	0.96618	72.85
23.5	439,711,190	15,459,133	0.03516	0.96484	70.39
24.5	421,187,683	18,690,989	0.04438	0.95562	67.92
25.5	395,218,406	17,673,692	0.04472	0.95528	64.91
26.5	369,388,598	16,257,720	0.04401	0.95599	62.01

Enbridge Gas Inc.

Account 473.01 - Distribution - Services - Metal

Placement Band - 1884 - 2021 Experience Band - 1956 - 2021

27.5	347,091,514	14,530,376	0.04186	0.95814	59.28
28.5	327,173,025	13,338,403	0.04077	0.95923	56.80
29.5	309,674,366	12,145,991	0.03922	0.96078	54.48
30.5	294,480,412	10,857,620	0.03687	0.96313	52.34
31.5	280,350,194	10,334,644	0.03686	0.96314	50.41
32.5	266,848,153	8,732,035	0.03272	0.96728	48.55
33.5	255,307,972	7,856,702	0.03077	0.96923	46.96
34.5	244,785,079	6,767,640	0.02765	0.97235	45.52
35.5	235,382,899	5,956,960	0.02531	0.97469	44.26
36.5	227,036,472	5,395,752	0.02377	0.97623	43.14
37.5	218,595,705	4,554,231	0.02083	0.97917	42.11
38.5	211,396,546	3,864,398	0.01828	0.98172	41.23
39.5	204,554,608	2,965,883	0.01450	0.98550	40.48
40.5	195,683,565	2,579,414	0.01318	0.98682	39.89
41.5	182,375,331	2,167,610	0.01189	0.98811	39.36
42.5	170,691,694	2,023,477	0.01185	0.98815	38.89
43.5	159,742,980	1,656,886	0.01037	0.98963	38.43
44.5	149,611,630	1,373,545	0.00918	0.99082	38.03
45.5	140,366,182	1,168,228	0.00832	0.99168	37.68
46.5	130,961,526	1,392,908	0.01064	0.98936	37.37
47.5	121,047,624	1,495,524	0.01235	0.98765	36.97
48.5	110,806,646	1,463,080	0.01320	0.98680	36.51
49.5	99,848,635	1,374,743	0.01377	0.98623	36.03
50.5	91,417,736	1,015,373	0.01111	0.98889	35.53
51.5	84,456,438	1,225,383	0.01451	0.98549	35.14
52.5	74,437,260	1,211,170	0.01627	0.98373	34.63
53.5	67,070,016	999,654	0.01490	0.98510	34.07
54.5	60,791,965	775,722	0.01276	0.98724	33.56
55.5	55,561,647	1,269,058	0.02284	0.97716	33.13
56.5	49,890,831	836,380	0.01676	0.98324	32.37
57.5	44,658,950	723,170	0.01619	0.98381	31.83

Enbridge Gas Inc.

Account 473.01 - Distribution - Services - Metal

Placement Band - 1884 - 2021 Experience Band - 1956 - 2021

58.5	37,983,111	622,526	0.01639	0.98361	31.31
59.5	30,421,713	657,190	0.02160	0.97840	30.80
60.5	24,260,219	761,313	0.03138	0.96862	30.13
61.5	19,295,888	646,103	0.03348	0.96652	29.18
62.5	15,726,277	552,581	0.03514	0.96486	28.20
63.5	12,215,129	504,302	0.04129	0.95871	27.21
64.5	10,138,102	441,393	0.04354	0.95646	26.09
65.5	8,906,432	383,358	0.04304	0.95696	24.95
66.5	8,129,108	355,336	0.04371	0.95629	23.88
67.5	6,412,801	331,843	0.05175	0.94825	22.84
68.5	6,074,235	312,794	0.05150	0.94850	21.66
69.5	5,758,017	287,967	0.05001	0.94999	20.54
70.5	5,467,527	257,569	0.04711	0.95289	19.51
71.5	5,199,835	239,332	0.04603	0.95397	18.59
72.5	4,960,285	218,045	0.04396	0.95604	17.73
73.5	4,741,449	191,668	0.04042	0.95958	16.95
74.5	4,549,448	181,847	0.03997	0.96003	16.26
75.5	4,366,705	149,132	0.03415	0.96585	15.61
76.5	4,215,867	127,721	0.03030	0.96970	15.08
77.5	4,088,082	113,708	0.02781	0.97219	14.62
78.5	3,973,899	93,185	0.02345	0.97655	14.21
79.5	3,879,116	82,910	0.02137	0.97863	13.88
80.5	3,795,245	73,388	0.01934	0.98066	13.58
81.5	3,721,171	57,298	0.01540	0.98460	13.32
82.5	3,661,634	48,618	0.01328	0.98672	13.11
83.5	3,594,681	38,623	0.01074	0.98926	12.94
84.5	3,554,119	30,321	0.00853	0.99147	12.80
85.5	3,523,215	20,708	0.00588	0.99412	12.69
86.5	3,501,058	18,488	0.00528	0.99472	12.62
87.5	3,482,276	9,329	0.00268	0.99732	12.55
88.5	3,472,881	6,435	0.00185	0.99815	12.52

Enbridge Gas Inc.

Account 473.01 - Distribution - Services - Metal

Placement Band - 1884 - 2021 Experience Band - 1956 - 2021

89.5	3,465,646	1,133	0.00033	0.99967	12.50
90.5	3,463,915	211	0.00006	0.99994	12.50
91.5	3,462,338	82	0.00002	0.99998	12.50
92.5	3,461,985	48	0.00001	0.99999	12.50
93.5	3,424,900	0	0.00000	1.00000	12.50
94.5	3,424,752	19	0.00001	0.99999	12.50
95.5	3,424,640	90	0.00003	0.99997	12.50
96.5	3,424,542	41	0.00001	0.99999	12.50
97.5	3,423,991	342	0.00010	0.99990	12.50
98.5	3,423,267	1,006	0.00029	0.99971	12.50
99.5	3,421,948	447	0.00013	0.99987	12.50
100.5	3,420,951	1,428	0.00042	0.99958	12.50
101.5	3,418,590	1,364	0.00040	0.99960	12.49
102.5	3,416,864	1,118	0.00033	0.99967	12.49
103.5	3,415,313	247	0.00007	0.99993	12.49
104.5	3,414,818	657	0.00019	0.99981	12.49
105.5	3,413,668	0	0.00000	1.00000	12.49
106.5	3,413,269	0	0.00000	1.00000	12.49
107.5	3,411,322	0	0.00000	1.00000	12.49
108.5	3,409,324	0	0.00000	1.00000	12.49
109.5	3,403,952	23,159	0.00680	0.99320	12.49
110.5	3,378,799	47,124	0.01395	0.98605	12.41
111.5	3,331,675	166,277	0.04991	0.95009	12.24
112.5	3,165,337	161,334	0.05097	0.94903	11.63
113.5	3,004,003	133,346	0.04439	0.95561	11.04
114.5	2,870,657	98,344	0.03426	0.96574	10.55
115.5	2,772,314	74,036	0.02671	0.97329	10.19
116.5	2,698,278	73,807	0.02735	0.97265	9.92
117.5	2,624,471	70,612	0.02691	0.97309	9.65
118.5	2,553,859	0	0.00000	1.00000	9.39
119.5	2,553,859	0	0.00000	1.00000	9.39

Enbridge Gas Inc.

Account 473.01 - Distribution - Services - Metal

Placement Band - 1884 - 2021 Experience Band - 1956 - 2021

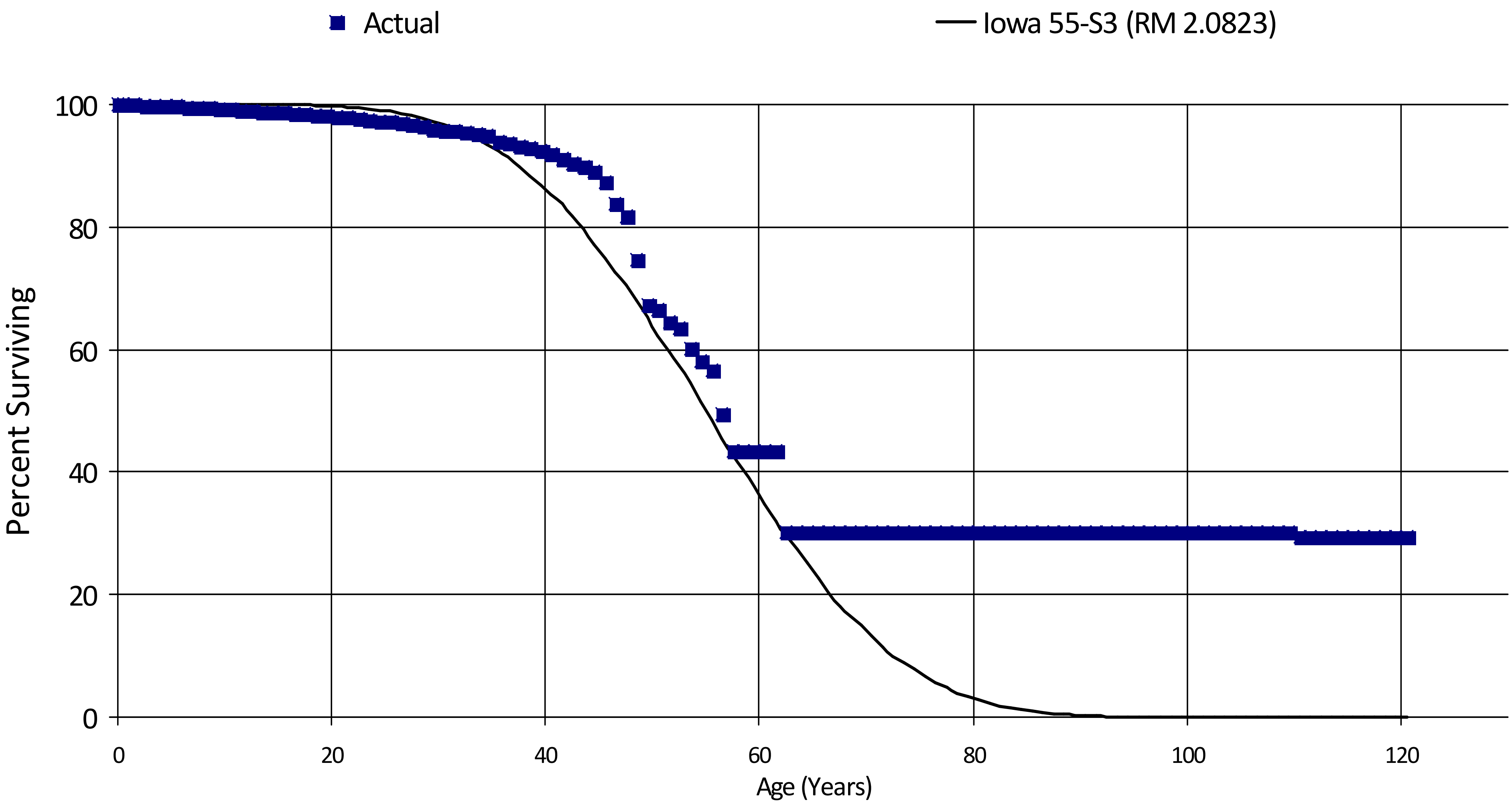
120.5	2,525,391	0	0.00000	1.00000	9.39
121.5	0	0	0.00000	0.00000	9.39
	Totals:	412,988,869			

Enbridge Gas Inc.

Account 473.02 - Distribution - Services - Plastic

Placement Band - 1900 - 2021 Experience Band - 2010 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 473.02 - Distribution - Services - Plastic

Placement Band - 1900 - 2021   Experience Band - 2010 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,555,581,934	454,072	0.00010	0.99990	100.00
0.5	4,210,013,762	2,290,439	0.00054	0.99946	99.99
1.5	4,043,417,172	2,814,850	0.00070	0.99930	99.94
2.5	3,859,792,322	2,351,234	0.00061	0.99939	99.87
3.5	3,705,730,163	2,136,526	0.00058	0.99942	99.81
4.5	3,560,851,536	2,379,624	0.00067	0.99933	99.75
5.5	3,410,101,354	2,971,034	0.00087	0.99913	99.68
6.5	3,256,368,719	3,693,201	0.00113	0.99887	99.59
7.5	3,120,573,477	3,527,042	0.00113	0.99887	99.48
8.5	2,978,399,477	3,444,635	0.00116	0.99884	99.37
9.5	2,836,698,250	2,867,782	0.00101	0.99899	99.25
10.5	2,717,908,331	2,645,660	0.00097	0.99903	99.15
11.5	2,588,836,463	3,064,213	0.00118	0.99882	99.05
12.5	2,507,710,380	2,370,904	0.00095	0.99905	98.93
13.5	2,392,169,147	2,457,937	0.00103	0.99897	98.84
14.5	2,284,281,013	2,673,646	0.00117	0.99883	98.74
15.5	2,171,903,195	2,085,926	0.00096	0.99904	98.62
16.5	2,072,422,162	2,294,412	0.00111	0.99889	98.53
17.5	2,000,773,957	3,129,282	0.00156	0.99844	98.42
18.5	1,882,439,431	2,223,445	0.00118	0.99882	98.27
19.5	1,783,966,373	2,410,902	0.00135	0.99865	98.15
20.5	1,666,265,578	2,941,493	0.00177	0.99823	98.02
21.5	1,535,308,192	2,857,288	0.00186	0.99814	97.85
22.5	1,420,099,223	2,265,247	0.00160	0.99840	97.67
23.5	1,310,961,374	2,614,488	0.00199	0.99801	97.51
24.5	1,197,333,152	2,738,682	0.00229	0.99771	97.32
25.5	1,071,931,942	2,598,157	0.00242	0.99758	97.10
26.5	924,644,322	2,338,849	0.00253	0.99747	96.87

Enbridge Gas Inc.

Account 473.02 - Distribution - Services - Plastic

Placement Band - 1900 - 2021   Experience Band - 2010 - 2021

27.5	807,692,010	1,902,350	0.00236	0.99764	96.62
28.5	705,373,321	2,503,827	0.00355	0.99645	96.39
29.5	616,614,767	1,537,517	0.00249	0.99751	96.05
30.5	547,032,170	1,354,780	0.00248	0.99752	95.81
31.5	484,095,677	1,164,869	0.00241	0.99759	95.57
32.5	429,831,241	953,316	0.00222	0.99778	95.34
33.5	376,155,876	829,068	0.00220	0.99780	95.13
34.5	327,143,506	3,519,906	0.01076	0.98924	94.92
35.5	277,967,054	814,553	0.00293	0.99707	93.90
36.5	232,973,598	933,896	0.00401	0.99599	93.62
37.5	186,987,885	734,470	0.00393	0.99607	93.24
38.5	153,465,373	681,211	0.00444	0.99556	92.87
39.5	123,933,552	818,551	0.00660	0.99340	92.46
40.5	92,516,609	741,001	0.00801	0.99199	91.85
41.5	69,548,946	542,563	0.00780	0.99220	91.11
42.5	51,269,054	271,435	0.00529	0.99471	90.40
43.5	40,522,391	403,380	0.00995	0.99005	89.92
44.5	31,860,795	623,074	0.01956	0.98044	89.03
45.5	24,423,469	961,243	0.03936	0.96064	87.29
46.5	17,341,346	456,235	0.02631	0.97369	83.85
47.5	12,864,060	1,095,210	0.08514	0.91486	81.64
48.5	6,852,799	675,436	0.09856	0.90144	74.69
49.5	6,081,220	72,406	0.01191	0.98809	67.33
50.5	3,558,303	110,593	0.03108	0.96892	66.53
51.5	1,883,912	25,873	0.01373	0.98627	64.46
52.5	1,853,974	99,704	0.05378	0.94622	63.57
53.5	938,311	32,532	0.03467	0.96533	60.15
54.5	708,383	18,689	0.02638	0.97362	58.06
55.5	533,370	67,175	0.12594	0.87406	56.53
56.5	317,848	38,568	0.12134	0.87866	49.41
57.5	231,929	0	0.00000	1.00000	43.41

Enbridge Gas Inc.

Account 473.02 - Distribution - Services - Plastic

Placement Band - 1900 - 2021   Experience Band - 2010 - 2021

58.5	231,929	0	0.00000	1.00000	43.41
59.5	231,929	0	0.00000	1.00000	43.41
60.5	229,812	0	0.00000	1.00000	43.41
61.5	229,812	70,373	0.30622	0.69378	43.41
62.5	156,712	0	0.00000	1.00000	30.12
63.5	155,187	0	0.00000	1.00000	30.12
64.5	155,187	0	0.00000	1.00000	30.12
65.5	155,187	0	0.00000	1.00000	30.12
66.5	155,187	0	0.00000	1.00000	30.12
67.5	155,187	0	0.00000	1.00000	30.12
68.5	155,187	0	0.00000	1.00000	30.12
69.5	155,187	0	0.00000	1.00000	30.12
70.5	155,187	0	0.00000	1.00000	30.12
71.5	155,187	0	0.00000	1.00000	30.12
72.5	155,187	0	0.00000	1.00000	30.12
73.5	155,187	0	0.00000	1.00000	30.12
74.5	155,187	0	0.00000	1.00000	30.12
75.5	155,187	0	0.00000	1.00000	30.12
76.5	155,187	0	0.00000	1.00000	30.12
77.5	155,187	0	0.00000	1.00000	30.12
78.5	155,187	0	0.00000	1.00000	30.12
79.5	155,187	0	0.00000	1.00000	30.12
80.5	155,187	0	0.00000	1.00000	30.12
81.5	155,187	0	0.00000	1.00000	30.12
82.5	155,187	0	0.00000	1.00000	30.12
83.5	155,187	0	0.00000	1.00000	30.12
84.5	155,187	0	0.00000	1.00000	30.12
85.5	155,187	0	0.00000	1.00000	30.12
86.5	155,187	0	0.00000	1.00000	30.12
87.5	155,187	0	0.00000	1.00000	30.12
88.5	155,187	0	0.00000	1.00000	30.12

Enbridge Gas Inc.

Account 473.02 - Distribution - Services - Plastic

Placement Band - 1900 - 2021 Experience Band - 2010 - 2021

89.5	155,187	0	0.00000	1.00000	30.12
90.5	155,187	0	0.00000	1.00000	30.12
91.5	155,187	0	0.00000	1.00000	30.12
92.5	155,187	0	0.00000	1.00000	30.12
93.5	153,663	0	0.00000	1.00000	30.12
94.5	153,663	0	0.00000	1.00000	30.12
95.5	153,663	0	0.00000	1.00000	30.12
96.5	153,663	0	0.00000	1.00000	30.12
97.5	153,663	0	0.00000	1.00000	30.12
98.5	153,663	0	0.00000	1.00000	30.12
99.5	153,663	0	0.00000	1.00000	30.12
100.5	153,663	0	0.00000	1.00000	30.12
101.5	153,663	0	0.00000	1.00000	30.12
102.5	153,663	0	0.00000	1.00000	30.12
103.5	153,663	0	0.00000	1.00000	30.12
104.5	153,663	0	0.00000	1.00000	30.12
105.5	153,663	0	0.00000	1.00000	30.12
106.5	153,663	0	0.00000	1.00000	30.12
107.5	153,663	0	0.00000	1.00000	30.12
108.5	153,663	0	0.00000	1.00000	30.12
109.5	153,663	3,895	0.02535	0.97465	30.12
110.5	149,769	0	0.00000	1.00000	29.36
111.5	149,769	0	0.00000	1.00000	29.36
112.5	149,769	0	0.00000	1.00000	29.36
113.5	149,769	0	0.00000	1.00000	29.36
114.5	149,769	0	0.00000	1.00000	29.36
115.5	149,769	0	0.00000	1.00000	29.36
116.5	149,769	0	0.00000	1.00000	29.36
117.5	149,769	0	0.00000	1.00000	29.36
118.5	149,769	0	0.00000	1.00000	29.36
119.5	149,769	0	0.00000	1.00000	29.36

Enbridge Gas Inc.

Account 473.02 - Distribution - Services - Plastic

Placement Band - 1900 - 2021   Experience Band - 2010 - 2021

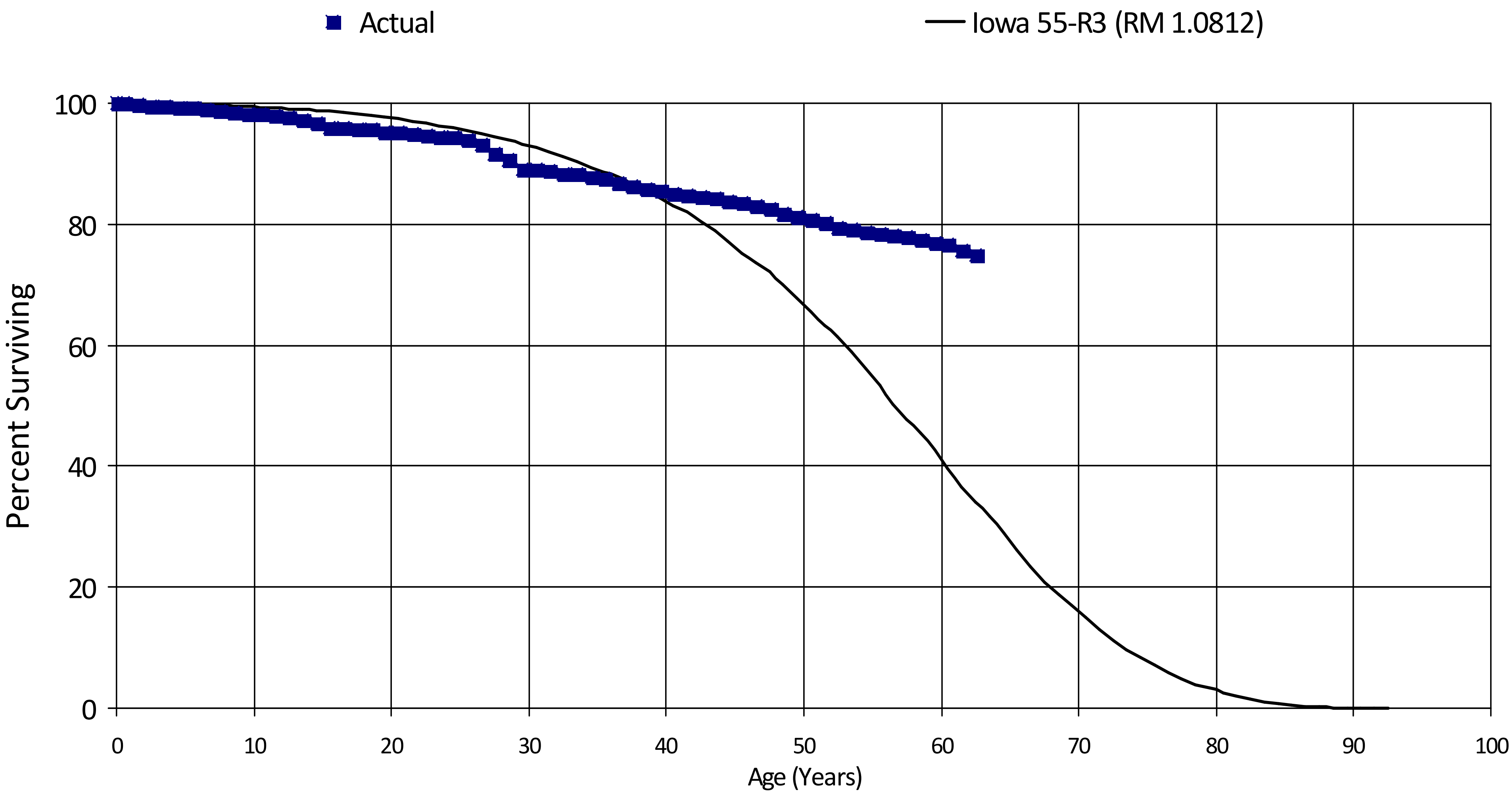
120.5	149,769	0	0.00000	1.00000	29.36
	Totals:	96,698,669			

Enbridge Gas Inc.

Account 475.21 - Distribution - Mains - Coated & Wrapped

Placement Band - 1894 - 2021 Experience Band - 1957 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 475.21 - Distribution - Mains - Coated & Wrapped

Placement Band - 1894 - 2021 Experience Band - 1957 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,530,236,877	3,852,951	0.00109	0.99891	100.00
0.5	3,162,572,043	4,806,315	0.00152	0.99848	99.89
1.5	2,978,913,938	6,682,874	0.00224	0.99776	99.74
2.5	2,830,411,525	3,509,572	0.00124	0.99876	99.52
3.5	2,630,147,548	2,527,670	0.00096	0.99904	99.40
4.5	2,518,191,135	3,808,987	0.00151	0.99849	99.30
5.5	2,055,621,467	4,889,146	0.00238	0.99762	99.15
6.5	1,982,496,419	3,525,588	0.00178	0.99822	98.91
7.5	1,831,750,927	2,884,273	0.00157	0.99843	98.73
8.5	1,749,955,598	4,190,510	0.00239	0.99761	98.57
9.5	1,716,647,977	2,462,518	0.00143	0.99857	98.33
10.5	1,657,456,162	2,446,387	0.00148	0.99852	98.19
11.5	1,626,403,660	5,999,047	0.00369	0.99631	98.04
12.5	1,574,302,799	7,947,775	0.00505	0.99495	97.68
13.5	1,516,111,924	7,740,749	0.00511	0.99489	97.19
14.5	1,421,898,400	9,283,349	0.00653	0.99347	96.69
15.5	1,358,213,159	2,130,926	0.00157	0.99843	96.06
16.5	1,315,695,456	1,671,700	0.00127	0.99873	95.91
17.5	1,288,309,360	1,725,891	0.00134	0.99866	95.79
18.5	1,266,040,555	4,903,782	0.00387	0.99613	95.66
19.5	1,216,640,574	1,682,377	0.00138	0.99862	95.29
20.5	1,172,861,655	1,767,601	0.00151	0.99849	95.16
21.5	1,136,666,286	3,869,456	0.00340	0.99660	95.02
22.5	1,088,966,220	2,284,535	0.00210	0.99790	94.70
23.5	1,051,084,081	1,792,275	0.00171	0.99829	94.50
24.5	1,022,493,945	3,634,681	0.00355	0.99645	94.34
25.5	982,406,733	9,811,877	0.00999	0.99001	94.01
26.5	933,095,065	15,134,844	0.01622	0.98378	93.07

Enbridge Gas Inc.

Account 475.21 - Distribution - Mains - Coated & Wrapped

Placement Band - 1894 - 2021   Experience Band - 1957 - 2021

27.5	874,027,838	9,076,681	0.01038	0.98962	91.56
28.5	838,947,197	13,279,346	0.01583	0.98417	90.61
29.5	798,179,959	1,579,866	0.00198	0.99802	89.18
30.5	722,076,647	2,366,691	0.00328	0.99672	89.00
31.5	679,032,600	1,976,410	0.00291	0.99709	88.71
32.5	637,807,695	1,673,801	0.00262	0.99738	88.45
33.5	616,790,341	2,875,598	0.00466	0.99534	88.22
34.5	582,855,105	1,652,350	0.00283	0.99717	87.81
35.5	566,496,162	5,552,130	0.00980	0.99020	87.56
36.5	546,326,705	1,747,863	0.00320	0.99680	86.70
37.5	525,059,238	4,496,748	0.00856	0.99144	86.42
38.5	499,136,372	1,596,957	0.00320	0.99680	85.68
39.5	484,206,686	1,567,308	0.00324	0.99676	85.41
40.5	468,315,980	2,091,416	0.00447	0.99553	85.13
41.5	451,492,677	1,291,416	0.00286	0.99714	84.75
42.5	433,443,253	1,330,143	0.00307	0.99693	84.51
43.5	417,115,552	1,958,738	0.00470	0.99530	84.25
44.5	398,175,710	1,756,771	0.00441	0.99559	83.85
45.5	379,878,867	1,940,091	0.00511	0.99489	83.48
46.5	364,730,075	2,188,022	0.00600	0.99400	83.05
47.5	342,785,662	2,994,352	0.00874	0.99126	82.55
48.5	319,616,056	2,071,972	0.00648	0.99352	81.83
49.5	298,996,263	2,309,680	0.00772	0.99228	81.30
50.5	277,597,896	1,980,783	0.00714	0.99286	80.67
51.5	257,472,435	1,715,960	0.00666	0.99334	80.09
52.5	236,687,090	1,431,597	0.00605	0.99395	79.56
53.5	218,685,126	924,697	0.00423	0.99577	79.08
54.5	196,670,718	727,759	0.00370	0.99630	78.75
55.5	182,787,004	797,861	0.00436	0.99564	78.46
56.5	170,436,363	667,408	0.00392	0.99608	78.12
57.5	158,959,131	749,986	0.00472	0.99528	77.81

Enbridge Gas Inc.

Account 475.21 - Distribution - Mains - Coated & Wrapped

Placement Band - 1894 - 2021   Experience Band - 1957 - 2021

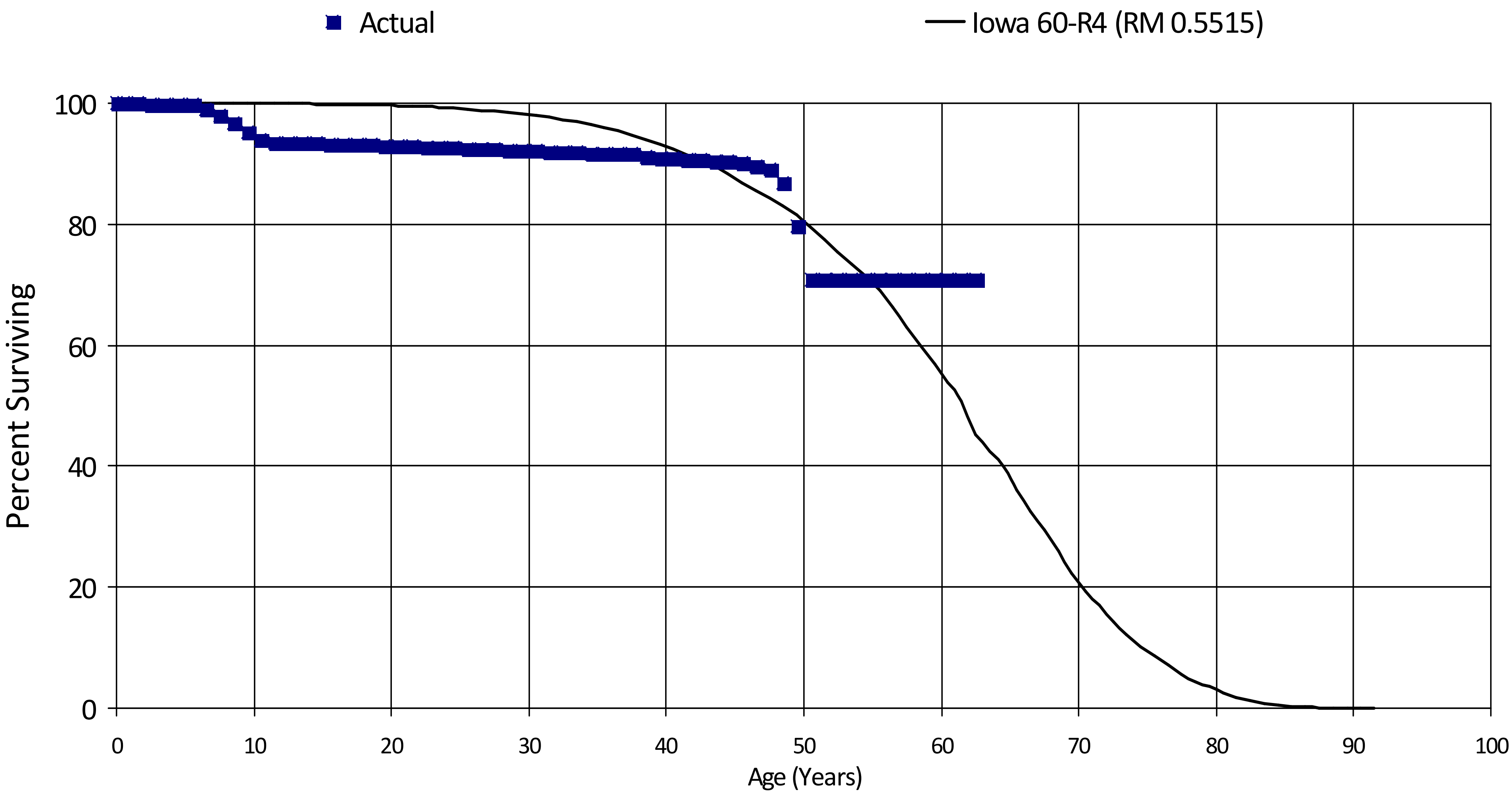
58.5	140,269,500	947,087	0.00675	0.99325	77.44
59.5	116,995,478	572,083	0.00489	0.99511	76.92
60.5	99,865,135	1,317,136	0.01319	0.98681	76.54
61.5	84,311,545	723,740	0.00858	0.99142	75.53
62.5	46,898,330	96,009	0.00205	0.99795	74.88
	Totals:	208,994,112			

Enbridge Gas Inc.

Account 475.30 - Distribution - Mains - Plastic

Placement Band - 1958 - 2021   Experience Band - 1971 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 475.30 - Distribution - Mains - Plastic

Placement Band - 1958 - 2021 Experience Band - 1971 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,659,693,969	937,528	0.00026	0.99974	100.00
0.5	3,277,821,241	2,421,787	0.00074	0.99926	99.97
1.5	3,132,345,282	1,719,695	0.00055	0.99945	99.90
2.5	3,009,125,684	1,343,907	0.00045	0.99955	99.85
3.5	2,883,925,344	1,004,750	0.00035	0.99965	99.81
4.5	2,748,374,798	3,661,922	0.00133	0.99867	99.78
5.5	2,625,777,036	19,399,522	0.00739	0.99261	99.65
6.5	2,517,540,045	25,025,257	0.00994	0.99006	98.91
7.5	2,398,051,004	31,678,784	0.01321	0.98679	97.93
8.5	2,268,428,618	35,523,959	0.01566	0.98434	96.64
9.5	2,140,625,513	29,501,059	0.01378	0.98622	95.13
10.5	2,031,557,042	6,927,627	0.00341	0.99659	93.82
11.5	1,923,443,733	582,716	0.00030	0.99970	93.50
12.5	1,811,374,639	2,255,542	0.00125	0.99875	93.47
13.5	1,708,947,985	837,259	0.00049	0.99951	93.35
14.5	1,591,031,878	993,070	0.00062	0.99938	93.30
15.5	1,459,496,245	1,166,062	0.00080	0.99920	93.24
16.5	1,386,983,364	956,404	0.00069	0.99931	93.17
17.5	1,336,543,304	954,634	0.00071	0.99929	93.11
18.5	1,266,120,974	912,060	0.00072	0.99928	93.04
19.5	1,195,035,733	1,453,156	0.00122	0.99878	92.97
20.5	1,106,768,535	879,770	0.00079	0.99921	92.86
21.5	1,022,334,714	1,044,200	0.00102	0.99898	92.79
22.5	933,160,210	1,055,045	0.00113	0.99887	92.70
23.5	844,950,040	760,912	0.00090	0.99910	92.60
24.5	762,999,726	786,365	0.00103	0.99897	92.52
25.5	681,516,216	633,598	0.00093	0.99907	92.42
26.5	596,799,094	408,972	0.00069	0.99931	92.33

Enbridge Gas Inc.

Account 475.30 - Distribution - Mains - Plastic

Placement Band - 1958 - 2021   Experience Band - 1971 - 2021

27.5	524,983,792	518,997	0.00099	0.99901	92.27
28.5	478,804,428	465,849	0.00097	0.99903	92.18
29.5	436,022,264	339,128	0.00078	0.99922	92.09
30.5	391,353,742	288,712	0.00074	0.99926	92.02
31.5	357,491,279	234,300	0.00066	0.99934	91.95
32.5	314,022,807	403,507	0.00128	0.99872	91.89
33.5	284,105,572	235,530	0.00083	0.99917	91.77
34.5	252,371,067	176,041	0.00070	0.99930	91.69
35.5	226,599,373	172,676	0.00076	0.99924	91.63
36.5	201,352,549	92,760	0.00046	0.99954	91.56
37.5	169,474,161	973,353	0.00574	0.99426	91.52
38.5	143,143,248	121,415	0.00085	0.99915	90.99
39.5	117,414,406	78,597	0.00067	0.99933	90.91
40.5	91,871,700	146,079	0.00159	0.99841	90.85
41.5	57,234,381	78,850	0.00138	0.99862	90.71
42.5	38,757,563	44,081	0.00114	0.99886	90.58
43.5	27,411,508	45,435	0.00166	0.99834	90.48
44.5	19,141,695	34,216	0.00179	0.99821	90.33
45.5	12,683,705	71,071	0.00560	0.99440	90.17
46.5	7,937,061	57,112	0.00720	0.99280	89.67
47.5	3,274,292	85,923	0.02624	0.97376	89.02
48.5	747,712	59,742	0.07990	0.92010	86.68
49.5	344,082	38,957	0.11322	0.88678	79.75
50.5	166,735	48	0.00029	0.99971	70.72
51.5	157,439	0	0.00000	1.00000	70.70
52.5	157,439	0	0.00000	1.00000	70.70
53.5	855	0	0.00000	1.00000	70.70
54.5	808	0	0.00000	1.00000	70.70
55.5	808	0	0.00000	1.00000	70.70
56.5	808	0	0.00000	1.00000	70.70
57.5	808	0	0.00000	1.00000	70.70

Enbridge Gas Inc.

Account 475.30 - Distribution - Mains - Plastic

Placement Band - 1958 - 2021 Experience Band - 1971 - 2021

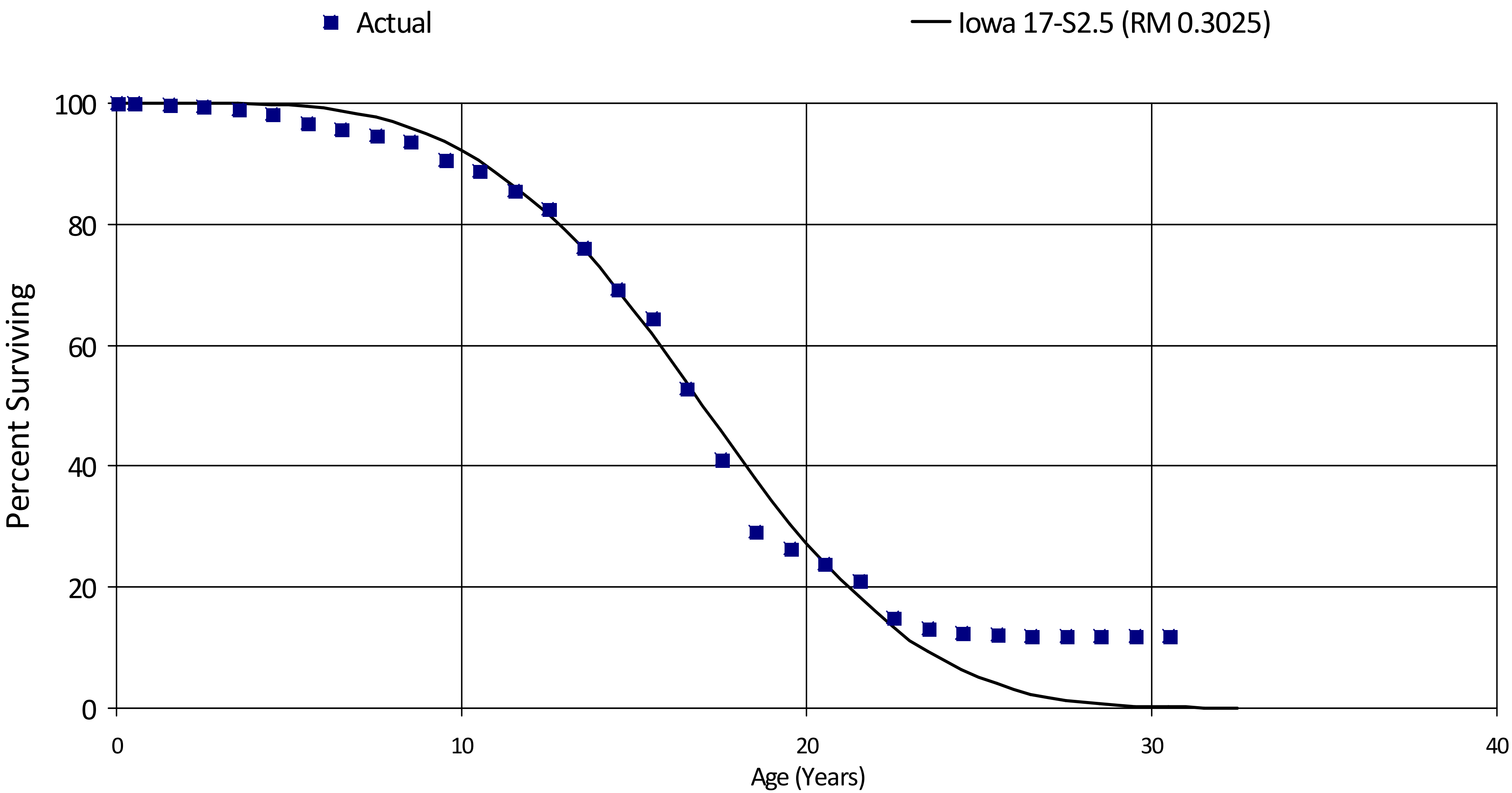
58.5	808	0	0.00000	1.00000	70.70
59.5	808	0	0.00000	1.00000	70.70
60.5	808	0	0.00000	1.00000	70.70
61.5	808	0	0.00000	1.00000	70.70
62.5	808	0	0.00000	1.00000	70.70
	Totals:	179,587,941			

Enbridge Gas Inc.

Account 476.00 - Distribution - Company NGV Compressor Stations

Placement Band - 1981 - 2021 Experience Band - 1990 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 476.00 - Distribution - Company NGV Compressor Stations

Placement Band - 1981 - 2021 Experience Band - 1990 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	23,607,965	24,888	0.00105	0.99895	100.00
0.5	22,227,663	58,913	0.00265	0.99735	99.90
1.5	21,397,162	58,370	0.00273	0.99727	99.64
2.5	19,964,549	83,947	0.00420	0.99580	99.37
3.5	17,728,626	146,896	0.00829	0.99171	98.95
4.5	16,870,055	244,642	0.01450	0.98550	98.13
5.5	16,424,793	156,361	0.00952	0.99048	96.71
6.5	16,111,900	186,594	0.01158	0.98842	95.79
7.5	15,677,632	163,778	0.01045	0.98955	94.68
8.5	15,245,609	516,674	0.03389	0.96611	93.69
9.5	14,728,935	280,787	0.01906	0.98094	90.51
10.5	14,448,148	541,430	0.03747	0.96253	88.78
11.5	13,552,008	473,925	0.03497	0.96503	85.45
12.5	13,078,083	1,018,152	0.07785	0.92215	82.46
13.5	12,059,931	1,070,362	0.08875	0.91125	76.04
14.5	10,989,569	754,229	0.06863	0.93137	69.29
15.5	10,235,340	1,879,353	0.18361	0.81639	64.53
16.5	8,120,846	1,763,917	0.21721	0.78279	52.68
17.5	6,356,929	1,863,704	0.29318	0.70682	41.24
18.5	4,493,225	434,552	0.09671	0.90329	29.15
19.5	4,058,673	388,828	0.09580	0.90420	26.33
20.5	3,305,121	377,218	0.11413	0.88587	23.81
21.5	2,927,903	843,330	0.28803	0.71197	21.09
22.5	2,084,573	249,877	0.11987	0.88013	15.02
23.5	1,746,485	90,269	0.05169	0.94831	13.22
24.5	1,360,189	32,475	0.02388	0.97612	12.54
25.5	1,298,686	25,616	0.01972	0.98028	12.24
26.5	1,273,070	0	0.00000	1.00000	12.00

Enbridge Gas Inc.

Account 476.00 - Distribution - Company NGV Compressor Stations

Placement Band - 1981 - 2021   Experience Band - 1990 - 2021

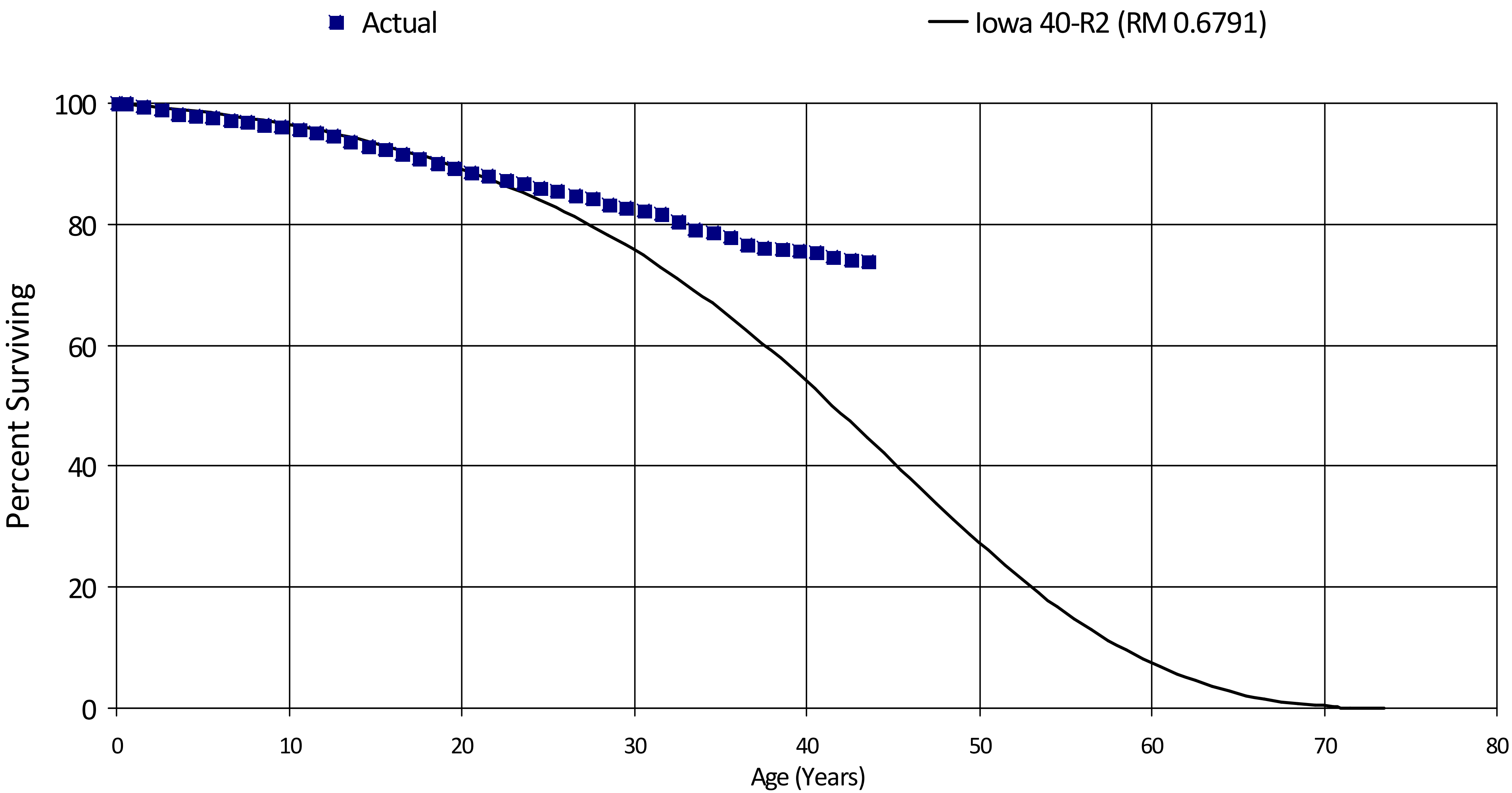
27.5	942,435	176	0.00019	0.99981	12.00
28.5	942,259	0	0.00000	1.00000	12.00
29.5	942,259	0	0.00000	1.00000	12.00
30.5	0	0	0.00000	0.00000	12.00
	Totals:	13,729,263			

Enbridge Gas Inc.

Account 477.00 - Distribution - Measuring and Regulating Equipment

Placement Band - 1949 - 2021 Experience Band - 1956 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 477.00 - Distribution - Measuring and Regulating Equipment

Placement Band - 1949 - 2021   Experience Band - 1956 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,034,272,645	242,777	0.00023	0.99977	100.00
0.5	970,667,601	4,155,004	0.00428	0.99572	99.98
1.5	902,279,182	5,977,061	0.00662	0.99338	99.55
2.5	868,044,197	6,253,962	0.00720	0.99280	98.89
3.5	834,455,985	1,709,024	0.00205	0.99795	98.18
4.5	780,823,226	2,326,801	0.00298	0.99702	97.98
5.5	656,421,987	3,264,012	0.00497	0.99503	97.69
6.5	611,431,014	1,872,144	0.00306	0.99694	97.20
7.5	573,005,430	2,455,746	0.00429	0.99571	96.90
8.5	543,393,538	2,165,064	0.00398	0.99602	96.48
9.5	512,360,656	2,288,186	0.00447	0.99553	96.10
10.5	487,965,566	2,617,259	0.00536	0.99464	95.67
11.5	468,710,475	2,633,045	0.00562	0.99438	95.16
12.5	440,126,185	4,072,780	0.00925	0.99075	94.63
13.5	409,960,141	3,238,205	0.00790	0.99210	93.75
14.5	385,311,722	2,785,012	0.00723	0.99277	93.01
15.5	360,552,028	2,669,303	0.00740	0.99260	92.34
16.5	340,221,416	3,147,220	0.00925	0.99075	91.66
17.5	317,118,902	2,477,097	0.00781	0.99219	90.81
18.5	299,527,334	2,633,231	0.00879	0.99121	90.10
19.5	284,348,229	2,306,147	0.00811	0.99189	89.31
20.5	267,690,080	1,837,708	0.00687	0.99313	88.59
21.5	237,995,220	1,682,734	0.00707	0.99293	87.98
22.5	210,203,131	1,453,421	0.00691	0.99309	87.36
23.5	186,240,392	1,344,342	0.00722	0.99278	86.76
24.5	171,673,607	1,374,981	0.00801	0.99199	86.13
25.5	151,851,025	1,086,910	0.00716	0.99284	85.44
26.5	135,482,138	848,770	0.00626	0.99374	84.83

Enbridge Gas Inc.

Account 477.00 - Distribution - Measuring and Regulating Equipment

Placement Band - 1949 - 2021 Experience Band - 1956 - 2021

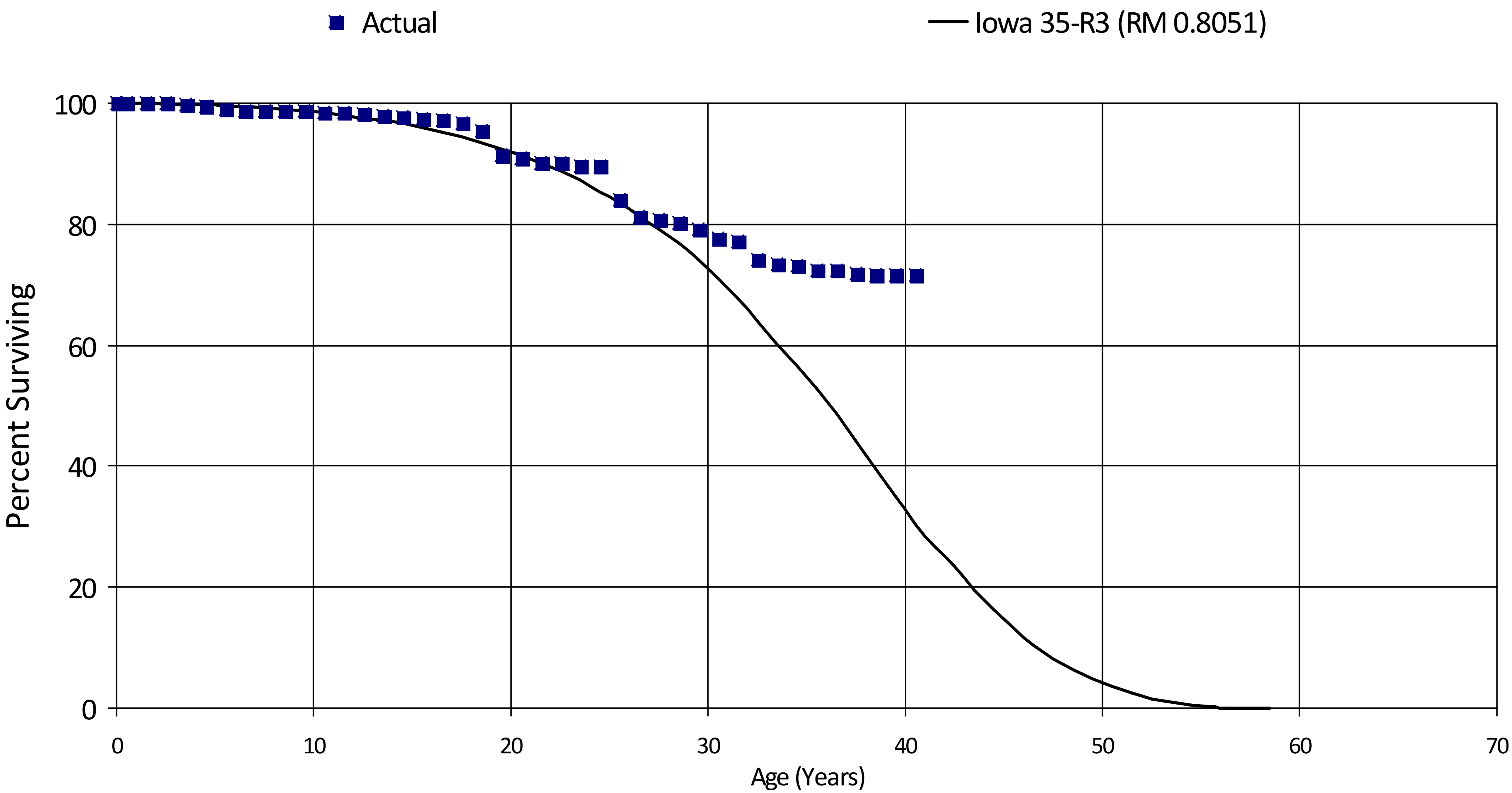
27.5	120,554,255	1,333,541	0.01106	0.98894	84.30
28.5	108,397,246	695,965	0.00642	0.99358	83.37
29.5	99,739,015	811,398	0.00814	0.99186	82.83
30.5	88,154,168	529,871	0.00601	0.99399	82.16
31.5	75,379,113	1,130,755	0.01500	0.98500	81.67
32.5	67,201,606	1,048,078	0.01560	0.98440	80.44
33.5	60,014,447	371,849	0.00620	0.99380	79.19
34.5	52,952,701	480,288	0.00907	0.99093	78.70
35.5	48,903,450	801,950	0.01640	0.98360	77.99
36.5	44,182,341	345,705	0.00782	0.99218	76.71
37.5	38,908,841	164,313	0.00422	0.99578	76.11
38.5	36,617,215	120,938	0.00330	0.99670	75.79
39.5	33,608,763	107,846	0.00321	0.99679	75.54
40.5	16,221,231	164,131	0.01012	0.98988	75.30
41.5	14,411,309	79,899	0.00554	0.99446	74.54
42.5	12,934,033	62,896	0.00486	0.99514	74.13
43.5	11,461,302	53,774	0.00469	0.99531	73.77
	Totals:	79,221,143			

Enbridge Gas Inc.

Account 477.01 - Distribution - Customer M&R Equipment

Placement Band - 1964 - 2021 Experience Band - 2010 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 477.01 - Distribution - Customer M&R Equipment

Placement Band - 1964 - 2021 Experience Band - 2010 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	157,737,408	7,766	0.00005	0.99995	100.00
0.5	132,479,863	109,893	0.00083	0.99917	100.00
1.5	128,743,776	31,503	0.00024	0.99976	99.92
2.5	125,652,547	314,611	0.00250	0.99750	99.90
3.5	120,957,154	134,649	0.00111	0.99889	99.65
4.5	110,566,580	477,167	0.00432	0.99568	99.54
5.5	107,814,061	314,026	0.00291	0.99709	99.11
6.5	105,574,185	75,874	0.00072	0.99928	98.82
7.5	100,652,951	77,067	0.00077	0.99923	98.75
8.5	97,560,608	37,188	0.00038	0.99962	98.67
9.5	96,009,304	159,571	0.00166	0.99834	98.63
10.5	94,141,304	96,301	0.00102	0.99898	98.47
11.5	93,544,878	234,944	0.00251	0.99749	98.37
12.5	84,974,591	152,564	0.00180	0.99820	98.12
13.5	74,778,783	222,144	0.00297	0.99703	97.94
14.5	72,605,118	205,438	0.00283	0.99717	97.65
15.5	64,690,052	138,656	0.00214	0.99786	97.37
16.5	63,114,630	308,037	0.00488	0.99512	97.16
17.5	60,129,414	776,617	0.01292	0.98708	96.69
18.5	56,066,960	2,417,025	0.04311	0.95689	95.44
19.5	50,949,562	261,573	0.00513	0.99487	91.33
20.5	49,979,321	352,603	0.00705	0.99295	90.86
21.5	48,545,222	57,172	0.00118	0.99882	90.22
22.5	47,132,408	207,917	0.00441	0.99559	90.11
23.5	45,716,247	101,135	0.00221	0.99779	89.71
24.5	44,862,347	2,730,329	0.06086	0.93914	89.51
25.5	35,570,369	1,218,714	0.03426	0.96574	84.06
26.5	30,271,336	197,233	0.00652	0.99348	81.18

Enbridge Gas Inc.

Account 477.01 - Distribution - Customer M&R Equipment

Placement Band - 1964 - 2021 Experience Band - 2010 - 2021

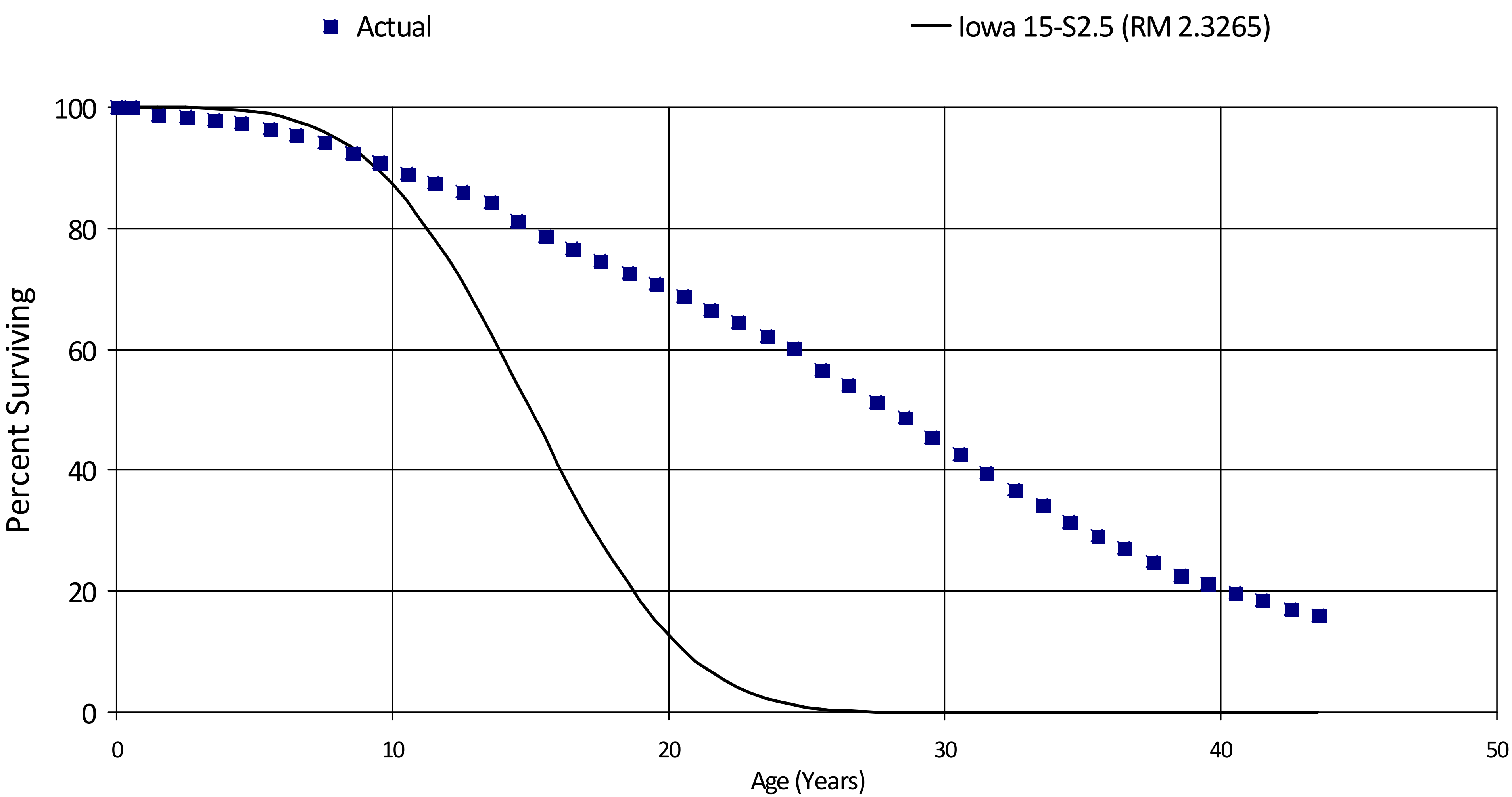
27.5	29,406,644	198,000	0.00673	0.99327	80.65
28.5	27,182,372	311,194	0.01145	0.98855	80.11
29.5	25,189,144	496,872	0.01973	0.98027	79.19
30.5	23,568,468	125,820	0.00534	0.99466	77.63
31.5	22,829,090	937,544	0.04107	0.95893	77.22
32.5	21,472,850	184,745	0.00860	0.99140	74.05
33.5	20,925,695	108,291	0.00518	0.99482	73.41
34.5	11,325,943	101,641	0.00897	0.99103	73.03
35.5	9,710,737	17,304	0.00178	0.99822	72.37
36.5	8,546,595	62,681	0.00733	0.99267	72.24
37.5	7,747,792	15,840	0.00204	0.99796	71.71
38.5	7,338,023	7,390	0.00101	0.99899	71.56
39.5	6,815,035	0	0.00000	1.00000	71.49
40.5	1,458,468	17,305	0.01187	0.98813	71.49
	Totals:	14,002,344			

Enbridge Gas Inc.

Account 478.00 - Distribution - Meters

Placement Band - 1884 - 2021   Experience Band - 1955 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 478.00 - Distribution - Meters

Placement Band - 1884 - 2021   Experience Band - 1955 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,433,933,198	1,431,590	0.00100	0.99900	100.00
0.5	1,330,494,640	14,599,562	0.01097	0.98903	99.90
1.5	1,244,981,357	5,554,153	0.00446	0.99554	98.80
2.5	1,187,514,732	5,975,373	0.00503	0.99497	98.36
3.5	1,128,635,158	5,548,667	0.00492	0.99508	97.87
4.5	1,066,934,325	9,713,485	0.00910	0.99090	97.39
5.5	1,009,481,699	10,577,210	0.01048	0.98952	96.50
6.5	938,111,922	13,052,681	0.01391	0.98609	95.49
7.5	881,750,332	15,650,082	0.01775	0.98225	94.16
8.5	828,265,994	15,708,678	0.01897	0.98103	92.49
9.5	770,957,819	13,137,063	0.01704	0.98296	90.74
10.5	717,422,536	13,748,738	0.01916	0.98084	89.19
11.5	668,898,329	10,905,967	0.01630	0.98370	87.48
12.5	626,362,344	13,770,295	0.02198	0.97802	86.05
13.5	581,918,828	20,940,732	0.03599	0.96401	84.16
14.5	534,833,737	16,601,037	0.03104	0.96896	81.13
15.5	490,796,804	12,958,546	0.02640	0.97360	78.61
16.5	454,040,177	11,292,341	0.02487	0.97513	76.53
17.5	432,333,562	12,035,284	0.02784	0.97216	74.63
18.5	401,840,728	10,252,069	0.02551	0.97449	72.55
19.5	375,736,659	10,693,124	0.02846	0.97154	70.70
20.5	349,525,390	11,349,831	0.03247	0.96753	68.69
21.5	321,526,125	9,123,756	0.02838	0.97162	66.46
22.5	300,394,737	10,541,375	0.03509	0.96491	64.57
23.5	273,441,795	9,664,800	0.03534	0.96466	62.30
24.5	250,008,915	15,040,454	0.06016	0.93984	60.10
25.5	221,253,175	9,418,288	0.04257	0.95743	56.48
26.5	189,866,592	9,543,913	0.05027	0.94973	54.08

Enbridge Gas Inc.

Account 478.00 - Distribution - Meters

Placement Band - 1884 - 2021 Experience Band - 1955 - 2021

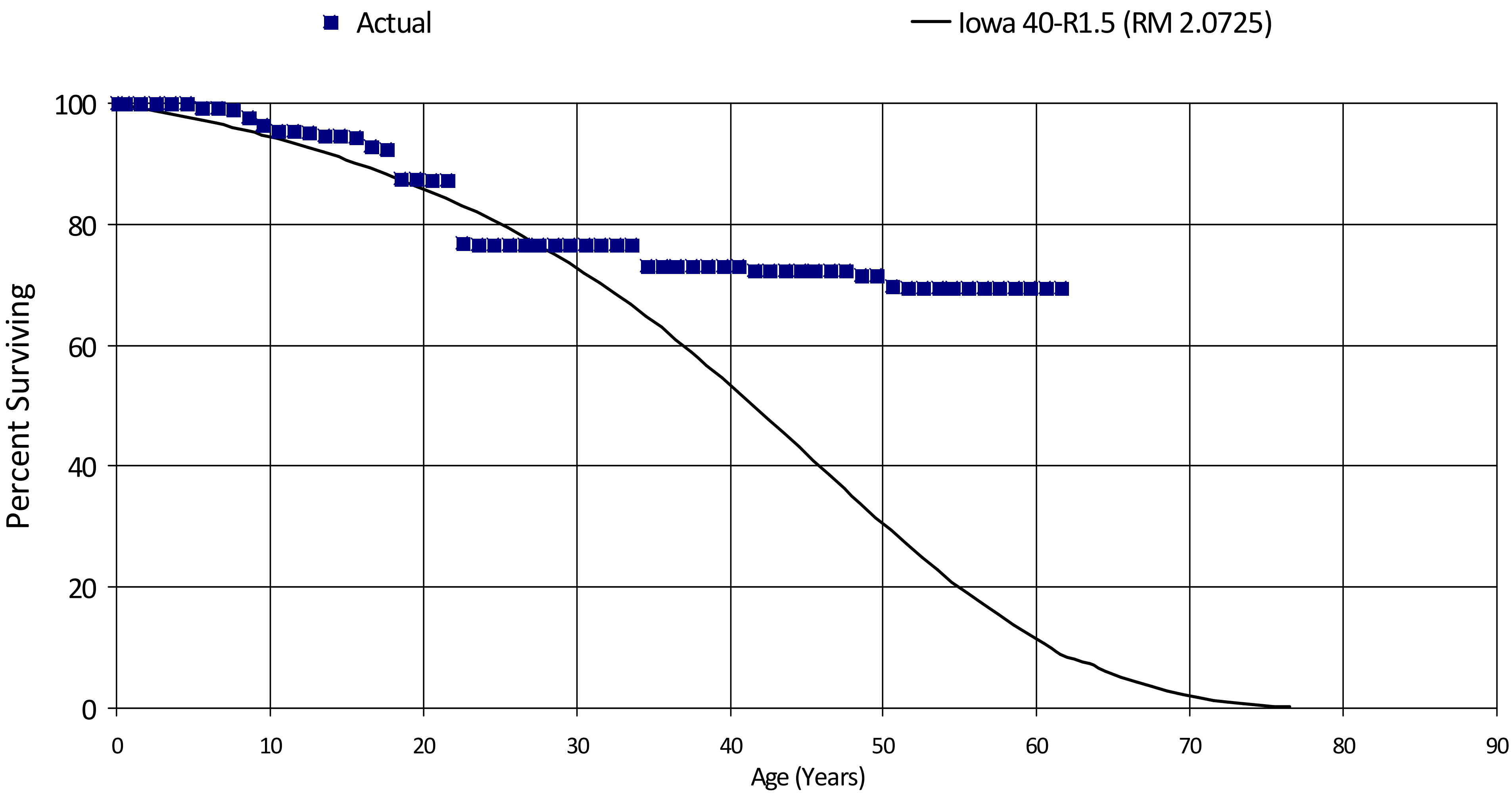
27.5	168,402,070	8,648,478	0.05136	0.94864	51.36
28.5	150,879,027	9,818,640	0.06508	0.93492	48.72
29.5	133,420,240	8,831,209	0.06619	0.93381	45.55
30.5	117,414,377	8,308,837	0.07077	0.92923	42.54
31.5	103,316,760	7,256,936	0.07024	0.92976	39.53
32.5	91,490,552	6,394,900	0.06990	0.93010	36.75
33.5	75,839,928	5,843,719	0.07705	0.92295	34.18
34.5	63,390,962	4,585,483	0.07234	0.92766	31.55
35.5	55,125,502	4,163,685	0.07553	0.92447	29.27
36.5	48,369,170	3,867,974	0.07997	0.92003	27.06
37.5	42,293,357	3,739,328	0.08841	0.91159	24.90
38.5	37,056,959	2,318,101	0.06256	0.93744	22.70
39.5	31,508,107	2,218,199	0.07040	0.92960	21.28
40.5	27,836,107	1,688,212	0.06065	0.93935	19.78
41.5	22,623,278	1,833,808	0.08106	0.91894	18.58
42.5	19,164,699	1,163,741	0.06072	0.93928	17.07
43.5	17,168,102	1,321,386	0.07697	0.92303	16.03
	Totals:	400,831,730			

Enbridge Gas Inc.

Account 482.00 - General Plant - Structures and Improvements

Placement Band - 1959 - 2021 Experience Band - 2011 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 482.00 - General Plant - Structures and Improvements

Placement Band - 1959 - 2021   Experience Band - 2011 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	225,321,799	0	0.00000	1.00000	100.00
0.5	204,621,153	0	0.00000	1.00000	100.00
1.5	204,031,640	44,417	0.00022	0.99978	100.00
2.5	198,661,976	0	0.00000	1.00000	99.98
3.5	186,804,650	0	0.00000	1.00000	99.98
4.5	169,192,659	1,167,375	0.00690	0.99310	99.98
5.5	153,529,195	55,296	0.00036	0.99964	99.29
6.5	126,501,690	389,568	0.00308	0.99692	99.25
7.5	124,154,115	1,598,880	0.01288	0.98712	98.94
8.5	113,325,489	1,346,034	0.01188	0.98812	97.67
9.5	73,925,048	788,456	0.01067	0.98933	96.51
10.5	70,216,843	100,120	0.00143	0.99857	95.48
11.5	66,952,526	123,180	0.00184	0.99816	95.34
12.5	65,567,875	333,204	0.00508	0.99492	95.16
13.5	63,534,489	0	0.00000	1.00000	94.68
14.5	56,990,437	120,880	0.00212	0.99788	94.68
15.5	54,918,792	904,428	0.01647	0.98353	94.48
16.5	49,937,996	341,712	0.00684	0.99316	92.92
17.5	47,496,892	2,493,540	0.05250	0.94750	92.28
18.5	44,361,038	0	0.00000	1.00000	87.44
19.5	43,720,969	11,571	0.00026	0.99974	87.44
20.5	43,687,615	0	0.00000	1.00000	87.42
21.5	42,409,950	5,133,083	0.12103	0.87897	87.42
22.5	37,227,012	32,229	0.00087	0.99913	76.84
23.5	37,194,782	0	0.00000	1.00000	76.77
24.5	36,814,928	0	0.00000	1.00000	76.77
25.5	36,814,928	0	0.00000	1.00000	76.77
26.5	33,981,692	0	0.00000	1.00000	76.77

Enbridge Gas Inc.

Account 482.00 - General Plant - Structures and Improvements

Placement Band - 1959 - 2021   Experience Band - 2011 - 2021

27.5	33,981,692	0	0.00000	1.00000	76.77
28.5	31,211,724	0	0.00000	1.00000	76.77
29.5	31,211,724	0	0.00000	1.00000	76.77
30.5	31,211,724	0	0.00000	1.00000	76.77
31.5	31,211,724	41,376	0.00133	0.99867	76.77
32.5	31,156,373	0	0.00000	1.00000	76.67
33.5	31,156,373	1,462,224	0.04693	0.95307	76.67
34.5	29,328,084	16,100	0.00055	0.99945	73.07
35.5	29,311,984	0	0.00000	1.00000	73.03
36.5	29,245,469	3,504	0.00012	0.99988	73.03
37.5	29,241,965	0	0.00000	1.00000	73.02
38.5	29,241,965	0	0.00000	1.00000	73.02
39.5	29,241,965	0	0.00000	1.00000	73.02
40.5	29,222,640	289,532	0.00991	0.99009	73.02
41.5	28,925,783	0	0.00000	1.00000	72.30
42.5	22,709,636	0	0.00000	1.00000	72.30
43.5	22,709,339	0	0.00000	1.00000	72.30
44.5	22,709,339	0	0.00000	1.00000	72.30
45.5	17,901,922	10,846	0.00061	0.99939	72.30
46.5	17,890,630	0	0.00000	1.00000	72.26
47.5	17,890,630	183,312	0.01025	0.98975	72.26
48.5	17,707,318	0	0.00000	1.00000	71.52
49.5	17,707,318	415,779	0.02348	0.97652	71.52
50.5	17,291,539	48,526	0.00281	0.99719	69.84
51.5	17,243,013	874	0.00005	0.99995	69.64
52.5	17,242,139	0	0.00000	1.00000	69.64
53.5	17,242,139	0	0.00000	1.00000	69.64
54.5	3,680,282	0	0.00000	1.00000	69.64
55.5	3,680,282	0	0.00000	1.00000	69.64
56.5	3,680,282	0	0.00000	1.00000	69.64
57.5	3,680,282	0	0.00000	1.00000	69.64

Enbridge Gas Inc.

Account 482.00 - General Plant - Structures and Improvements

Placement Band - 1959 - 2021   Experience Band - 2011 - 2021

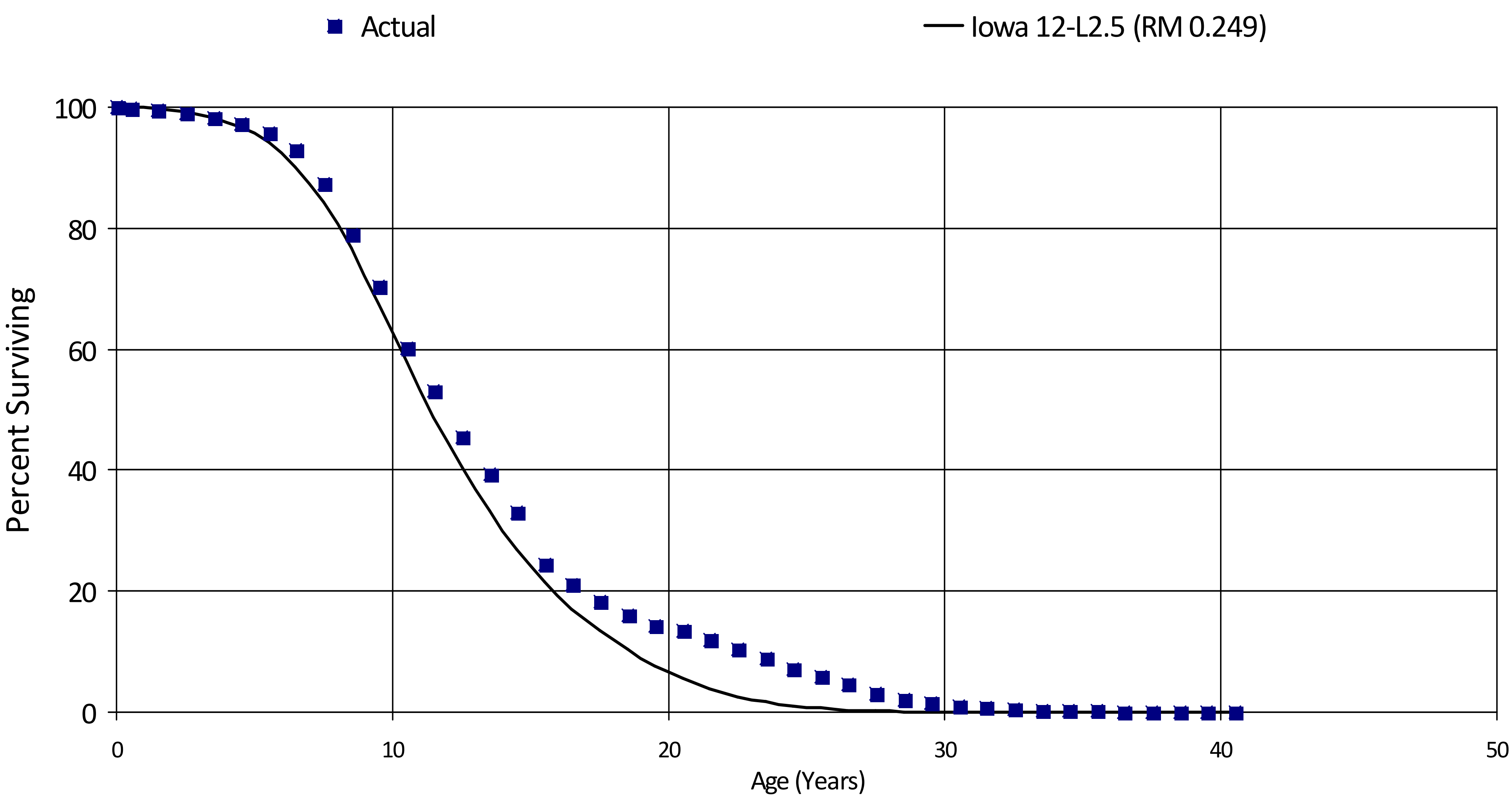
58.5	3,680,282	0	0.00000	1.00000	69.64
59.5	150,580	0	0.00000	1.00000	69.64
60.5	150,580	0	0.00000	1.00000	69.64
61.5	150,580	0	0.00000	1.00000	69.64
	Totals:	17,456,046			

Enbridge Gas Inc.

Account 484.00 - General Plant - Transportation Equipment

Placement Band - 1963 - 2021 Experience Band - 1966 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 484.00 - General Plant - Transportation Equipment

Placement Band - 1963 - 2021 Experience Band - 1966 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	262,873,101	726,657	0.00276	0.99724	100.00
0.5	253,102,021	345,528	0.00137	0.99863	99.72
1.5	242,338,900	1,266,184	0.00522	0.99478	99.58
2.5	223,801,737	1,642,576	0.00734	0.99266	99.06
3.5	212,273,047	2,317,129	0.01092	0.98908	98.33
4.5	198,323,448	3,107,075	0.01567	0.98433	97.26
5.5	190,319,295	5,813,453	0.03055	0.96945	95.74
6.5	171,428,671	10,307,674	0.06013	0.93987	92.82
7.5	148,016,737	14,054,698	0.09495	0.90505	87.24
8.5	124,637,615	13,488,521	0.10822	0.89178	78.96
9.5	106,352,236	15,393,164	0.14474	0.85526	70.41
10.5	80,253,171	9,567,090	0.11921	0.88079	60.22
11.5	65,864,709	9,572,224	0.14533	0.85467	53.04
12.5	52,996,481	6,988,108	0.13186	0.86814	45.33
13.5	39,281,425	6,276,725	0.15979	0.84021	39.35
14.5	30,149,608	7,815,537	0.25923	0.74077	33.06
15.5	20,956,760	2,908,071	0.13877	0.86123	24.49
16.5	17,211,839	2,286,700	0.13286	0.86714	21.09
17.5	14,858,688	1,916,575	0.12899	0.87101	18.29
18.5	12,925,991	1,422,908	0.11008	0.88992	15.93
19.5	11,274,054	528,762	0.04690	0.95310	14.18
20.5	10,702,517	1,252,005	0.11698	0.88302	13.51
21.5	9,432,460	1,174,125	0.12448	0.87552	11.93
22.5	8,172,185	1,310,345	0.16034	0.83966	10.44
23.5	6,811,298	1,223,437	0.17962	0.82038	8.77
24.5	5,535,635	1,118,175	0.20200	0.79800	7.19
25.5	4,333,466	794,871	0.18343	0.81657	5.74
26.5	3,532,708	1,201,895	0.34022	0.65978	4.69

Enbridge Gas Inc.

Account 484.00 - General Plant - Transportation Equipment

Placement Band - 1963 - 2021 Experience Band - 1966 - 2021

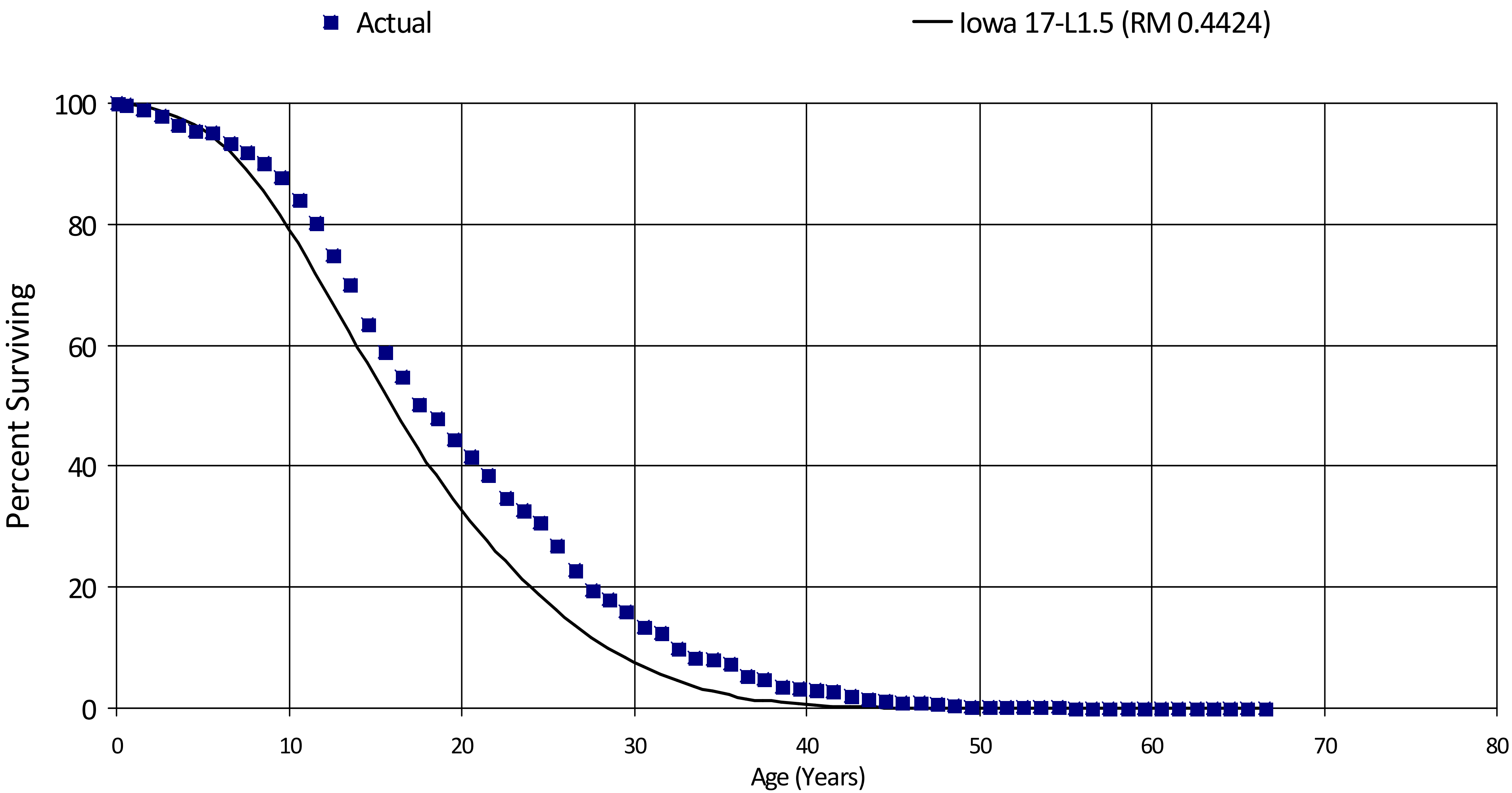
27.5	2,330,813	706,834	0.30326	0.69674	3.09
28.5	1,623,979	390,157	0.24025	0.75975	2.15
29.5	1,233,822	408,412	0.33101	0.66899	1.63
30.5	825,409	297,333	0.36022	0.63978	1.09
31.5	528,076	163,322	0.30928	0.69072	0.70
32.5	364,754	101,505	0.27828	0.72172	0.48
33.5	263,249	141,133	0.53612	0.46388	0.35
34.5	122,116	20,834	0.17061	0.82939	0.16
35.5	101,282	39,227	0.38730	0.61270	0.13
36.5	62,056	39,431	0.63541	0.36459	0.08
37.5	22,625	11,432	0.50529	0.49471	0.03
38.5	11,193	6,637	0.59297	0.40703	0.01
39.5	4,556	4,556	0.99994	0.00006	0.00
40.5	0	0	0.00000	0.00000	0.00
	Totals:	128,151,025			

Enbridge Gas Inc.

Account 485.00 - General Plant - Heavy Work Equipment

Placement Band - 1952 - 2021   Experience Band - 1961 - 2021

Actual and Smooth Survivor Curves



Enbridge Gas Inc.

Account 485.00 - General Plant - Heavy Work Equipment

Placement Band - 1952 - 2021   Experience Band - 1961 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	79,061,664	176,977	0.00224	0.99776	100.00
0.5	74,755,907	546,221	0.00731	0.99269	99.78
1.5	67,826,929	789,074	0.01163	0.98837	99.05
2.5	65,060,732	939,764	0.01444	0.98556	97.90
3.5	60,630,563	610,598	0.01007	0.98993	96.49
4.5	58,937,795	260,101	0.00441	0.99559	95.52
5.5	58,512,543	1,029,435	0.01759	0.98241	95.10
6.5	55,423,774	958,975	0.01730	0.98270	93.43
7.5	52,450,285	1,036,849	0.01977	0.98023	91.81
8.5	49,668,893	1,230,099	0.02477	0.97523	89.99
9.5	47,302,022	2,049,975	0.04334	0.95666	87.76
10.5	42,906,572	1,936,121	0.04512	0.95488	83.96
11.5	33,995,007	2,196,603	0.06462	0.93538	80.17
12.5	30,026,150	2,007,159	0.06685	0.93315	74.99
13.5	25,523,715	2,371,112	0.09290	0.90710	69.98
14.5	22,019,976	1,614,440	0.07332	0.92668	63.48
15.5	19,040,023	1,285,509	0.06752	0.93248	58.83
16.5	16,969,362	1,445,474	0.08518	0.91482	54.86
17.5	14,225,889	663,783	0.04666	0.95334	50.19
18.5	13,031,660	906,167	0.06954	0.93046	47.85
19.5	11,954,787	757,317	0.06335	0.93665	44.52
20.5	10,972,434	802,680	0.07315	0.92685	41.70
21.5	10,125,498	1,036,482	0.10236	0.89764	38.65
22.5	9,083,514	516,254	0.05683	0.94317	34.69
23.5	8,000,924	479,570	0.05994	0.94006	32.72
24.5	7,367,773	942,947	0.12798	0.87202	30.76
25.5	6,367,533	921,496	0.14472	0.85528	26.82
26.5	5,446,037	804,681	0.14776	0.85224	22.94

Enbridge Gas Inc.

Account 485.00 - General Plant - Heavy Work Equipment

Placement Band - 1952 - 2021 Experience Band - 1961 - 2021

27.5	4,641,356	377,956	0.08143	0.91857	19.55
28.5	4,263,399	486,778	0.11418	0.88582	17.96
29.5	3,776,621	562,619	0.14897	0.85103	15.91
30.5	3,189,525	263,143	0.08250	0.91750	13.54
31.5	2,926,382	589,966	0.20160	0.79840	12.42
32.5	2,336,416	340,384	0.14569	0.85431	9.92
33.5	1,996,032	102,705	0.05145	0.94855	8.47
34.5	1,893,327	176,249	0.09309	0.90691	8.03
35.5	1,717,078	439,901	0.25619	0.74381	7.28
36.5	1,277,177	114,172	0.08939	0.91061	5.41
37.5	1,163,005	300,421	0.25831	0.74169	4.93
38.5	862,584	103,132	0.11956	0.88044	3.66
39.5	759,452	55,129	0.07259	0.92741	3.22
40.5	704,323	32,392	0.04599	0.95401	2.99
41.5	671,930	208,743	0.31066	0.68934	2.85
42.5	463,188	87,732	0.18941	0.81059	1.96
43.5	375,456	92,438	0.24620	0.75380	1.59
44.5	283,018	24,560	0.08678	0.91322	1.20
45.5	258,459	32,176	0.12449	0.87551	1.10
46.5	226,283	26,335	0.11638	0.88362	0.96
47.5	199,949	98,940	0.49483	0.50517	0.85
48.5	101,009	30,266	0.29964	0.70036	0.43
49.5	70,743	16,113	0.22777	0.77223	0.30
50.5	54,629	0	0.00000	1.00000	0.23
51.5	54,629	15,676	0.28695	0.71305	0.23
52.5	38,954	0	0.00000	1.00000	0.16
53.5	38,954	0	0.00000	1.00000	0.16
54.5	38,954	8,788	0.22560	0.77440	0.16
55.5	30,166	1,507	0.04996	0.95004	0.12
56.5	28,659	0	0.00000	1.00000	0.11
57.5	28,659	0	0.00000	1.00000	0.11

Enbridge Gas Inc.

Account 485.00 - General Plant - Heavy Work Equipment

Placement Band - 1952 - 2021   Experience Band - 1961 - 2021

58.5	28,659	0	0.00000	1.00000	0.11
59.5	28,659	14,329	0.49998	0.50002	0.11
60.5	14,329	0	0.00000	1.00000	0.06
61.5	14,329	0	0.00000	1.00000	0.06
62.5	14,329	0	0.00000	1.00000	0.06
63.5	14,329	0	0.00000	1.00000	0.06
64.5	14,329	0	0.00000	1.00000	0.06
65.5	14,329	14,329	0.99997	0.00003	0.06
66.5	0	0	0.00000	0.00000	0.00
	Totals:	34,932,742			

SECTION 7

7 NET SALVAGE

ENBRIDGE GAS INC.

ACCOUNT 443.02 - LOCAL STORAGE PLANT - HOLDER EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010		(7,162)						-7,162	
2011		0						-7,162	
2012		0		-2,387	0			-7,162	
2013		0		0	0			-7,162	
2014	180,355	(9,984)	-6	-3,328	-6	-3,429	-10	-8,573	-10
2015		0		-3,328	-6	-1,997	-6	-8,573	-10
2016		(2,714)		-4,233	-7	-2,540	-7	-6,620	-11
2017		0		-905	0	-2,540	-7	-6,620	-11
2018		(2,141)		-1,618	0	-2,968	-8	-5,500	-12
2019		(461)		-867	0	-1,063	0	-4,492	-12
2020		(461)		-1,021	0	-1,155	0	-3,821	-13
2021		(4,503)		-1,808	0	-1,513	0	-3,918	-15
TOTAL	**180,355**	**-27,427**	**(15.21)**						

ENBRIDGE GAS INC.

ACCOUNT 452 - UNDERGROUND STORAGE PLANT - STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	67,929	(59,600)						-59,600	-88
2012		59,600							0
2013	28,833	0		0	0				0
2014	96,118	(36,063)		7,846	19			-12,021	-19
2015	2,661,993	0		-12,021	-1	-7,213	-1	-12,021	-1
2016	745,161	0		-12,021	-1	4,707	1	-12,021	-1
2017	503,030	(47,315)	-9	-15,772	-1	-16,676	-2	-20,844	-2
2018	1,249,056	7,319	1	-13,332	-2	-15,212	-1	-15,212	-1
2019	827,601	(164,696)	-20	-68,231	-8	-40,938	-3	-40,126	-4
2020	33,594	(165,351)	-492	-107,576	-15	-74,009	-11	-58,015	-7
2021	4,055,913	(166,678)	-4	-165,575	-10	-107,344	-8	-71,598	-6
TOTAL	**10,269,228**	**-572,785**	**(5.58)**						

ENBRIDGE GAS INC.

ACCOUNT 453 - UNDERGROUND STORAGE PLANT - WELLS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1994	156,007	(67,100)	-43					-67,100	-43
1995		0						-67,100	-43
1996		0		-22,367	-43			-67,100	-43
1997		0		0	0			-67,100	-43
1998		(13,409)		-4,470	0	-16,102	-52	-40,254	-52
1999		0		-4,470	0	-2,682	0	-40,254	-52
2000		0		-4,470	0	-2,682	0	-40,254	-52
2001		0		0	0	-2,682	0	-40,254	-52
2002		(95,264)		-31,755	0	-21,734	0	-58,591	-113
2003		0		-31,755	0	-19,053	0	-58,591	-113
2004		0		-31,755	0	-19,053	0	-58,591	-113
2005		0		0	0	-19,053	0	-58,591	-113
2006		0		0	0	-19,053	0	-58,591	-113
2007		0		0	0	0	0	-58,591	-113
2008		0		0	0	0	0	-58,591	-113
2009		(732,167)		-244,056	0	-146,433	0	-226,985	-582
2010		(60,102)		-264,090	0	-158,454	0	-193,608	-621
2011	20,133	(1,497,694)	-7,439	-763,321	-11,374	-457,993	-11,374	-410,956	-1,400
2012		(242,484)		-600,093	-8,942	-506,489	-12,579	-386,889	-1,538
2013	6,755	0	0	-580,059	-6,472	-506,489	-9,419	-386,889	-1,481
2014		(2,937,615)		-1,060,033	-47,080	-947,579	-17,621	-705,729	-3,087
2015	3,765,717	(23,984,280)	-637	-8,973,965	-714	-5,732,415	-756	-3,292,235	-750
2016	1,165,795	(4,341,932)	-372	-10,421,276	-634	-6,301,262	-638	-3,397,205	-664
2017	439,423	(6,777)	-2	-9,444,330	-528	-6,254,121	-581	-3,088,984	-612
2018		0		-1,449,570	-271	-6,254,121	-582	-3,088,984	-612
2019	2,401,819	(201,574)	-8	-69,450	-7	-5,706,913	-367	-2,848,367	-430

ENBRIDGE GAS INC.

ACCOUNT 453 - UNDERGROUND STORAGE PLANT - WELLS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2020	68,999	(189,379)	-274	-130,318	-16	-947,933	-116	-2,643,829	-428
2021	6,989,104	(208,338)	-3	-199,764	-6	-121,214	-6	-2,469,865	-230
TOTAL	**15,013,752**	**-34,578,116**	**(230.31)**						

ENBRIDGE GAS INC.

ACCOUNT 455 - UNDERGROUND STORAGE PLANT - FIELD LINES

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1996	81,442	(1,690)	-2					-1,690	-2
1997		0						-1,690	-2
1998		0		-563	-2			-1,690	-2
1999		0		0	0			-1,690	-2
2000		0		0	0	-338	-2	-1,690	-2
2001		0		0	0	0	0	-1,690	-2
2002		0		0	0	0	0	-1,690	-2
2003		0		0	0	0	0	-1,690	-2
2004		0		0	0	0	0	-1,690	-2
2005		0		0	0	0	0	-1,690	-2
2006		0		0	0	0	0	-1,690	-2
2007		0		0	0	0	0	-1,690	-2
2008		0		0	0	0	0	-1,690	-2
2009		0		0	0	0	0	-1,690	-2
2010		0		0	0	0	0	-1,690	-2
2011	4,576	0		0	0	0	0	-1,690	-2
2012		(820,413)		-273,471	-17,927	-164,083	-17,927	-411,051	-956
2013		(500,351)		-440,255	-28,861	-264,153	-28,861	-440,818	-1,537
2014	95,638	(74,376)		-465,047	-1,459	-279,028	-1,392	-349,208	-769
2015	302,956	(43)	0	-191,590	-144	-279,037	-346	-279,375	-288
2016	1,004,604	(409,390)	-41	-161,270	-34	-360,915	-129	-301,044	-121
2017	258,080	0	0	-136,478	-26	-196,832	-59	-301,044	-103
2018	1,523,662	0	0	-136,463	-15	-96,762	-15	-301,044	-55
2019		0		0	0	-81,887	-13	-301,044	-55
2020		0		0	0	-81,878	-15	-301,044	-55
2021	1,467,725	0	0	0	0	0	0	-301,044	-38
TOTAL	**4,738,683**	**-1,806,263**	**(38.12)**						

ENBRIDGE GAS INC.

ACCOUNT 456 - UNDERGROUND STORAGE PLANT - COMPRESSOR EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1993		13,166						13,166	0
1994		0						13,166	0
1995		0		4,389	0			13,166	0
1996		0		0	0			13,166	0
1997		0		0	0	2,633	0	13,166	0
1998		0		0	0	0	0	13,166	0
1999		0		0	0	0	0	13,166	0
2000		0		0	0	0	0	13,166	0
2001		0		0	0	0	0	13,166	0
2002		0		0	0	0	0	13,166	0
2003		0		0	0	0	0	13,166	0
2004		0		0	0	0	0	13,166	0
2005		0		0	0	0	0	13,166	0
2006		0		0	0	0	0	13,166	0
2007		0		0	0	0	0	13,166	0
2008		0		0	0	0	0	13,166	0
2009		0		0	0	0	0	13,166	0
2010	10,615,186	(13,207)	0	-4,402	0	-2,641	0	-20	0
2011	1,286,547	(2,019,065)	-157	-677,424	-17	-406,454	-17	-673,035	-17
2012	3,703,484	0	0	-677,424	-13	-406,454	-13	-673,035	-13
2013	1,118,061	(161,738)	-14	-726,934	-36	-438,802	-13	-545,211	-13
2014	252,088	(49,746)	-20	-70,495	-4	-448,751	-13	-446,118	-13
2015	4,060,345	(154)	0	-70,546	-4	-446,140	-21	-371,791	-11
2016	1,745.00	(17,132)	-982	-22,344	-2	-45,754	-3	-321,125	-11
2017		(65,443)		-27,576	-2	-58,842	-5	-289,165	-11
2018	21,926,588	(4,321,018)	-20	-1,467,864	-20	-890,699	-17	-737,148	-15
2019	1,046,806	(559,712)	-53	-1,648,724	-22	-992,692	-18	-719,405	-16

ENBRIDGE GAS INC.

ACCOUNT 456 - UNDERGROUND STORAGE PLANT - COMPRESSOR EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2020	2,079,480	(564,464)	-27	-1,815,065	-22	-1,105,554	-22	-705,319	-17
2021	5,094,704	(564,585)	-11	-562,920	-21	-1,215,044	-20	-693,591	-16
TOTAL	**51,185,032**	**-8,323,097**	**(16.26)**						

ENBRIDGE GAS INC.

ACCOUNT 457 - UNDERGROUND STORAGE PLANT - REGULATING AND MEASURING EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995		108						108	0
1996		0						108	0
1997		0		36	0			108	0
1998		0		0	0			108	0
1999		0		0	0	22	0	108	0
2000		0		0	0	0	0	108	0
2001		(7,560)		-2,520	0	-1,512	0	-3,726	0
2002		0		-2,520	0	-1,512	0	-3,726	0
2003		0		-2,520	0	-1,512	0	-3,726	0
2004		0		0	0	-1,512	0	-3,726	0
2005		0		0	0	-1,512	0	-3,726	0
2006		0		0	0	0	0	-3,726	0
2007		0		0	0	0	0	-3,726	0
2008		0		0	0	0	0	-3,726	0
2009		0		0	0	0	0	-3,726	0
2010	729.67	(21,507)	-2,947	-7,169	-2,947	-4,301	-2,947	-9,653	-3,969
2011		6,106		-5,134	-2,111	-3,080	-2,111	-5,713	-3,132
2012	5,467,932	(1,500)	0	-5,634	0	-3,380	0	-4,870	0
2013		(19,929)		-5,108	0	-7,366	-1	-7,380	-1
2014	163,833	19,929	12	-500	0	-3,380	0	-3,479	0
2015	423,536	(4,525)	-1	-1,508	-1	16	0	-3,610	0
2016	48,047	(1,375,444)	-2,863	-453,346	-214	-276,294	-23	-156,036	-23
2017	29,631	(207,434)	-700	-529,134	-317	-317,481	-239	-161,175	-26
2018	629,206	(1,307,020)	-208	-963,299	-409	-574,899	-222	-265,343	-43
2019	2,814,082	(249,596)	-9	-588,017	-51	-628,804	-80	-264,031	-33

ENBRIDGE GAS INC.

ACCOUNT 457 - UNDERGROUND STORAGE PLANT - REGULATING AND MEASURING EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2020		(250,787)		-602,468	-52	-678,056	-96	-263,012	-36
2021	556,189	(253,039)	-45	-251,140	-22	-453,575	-56	-262,300	-36
TOTAL	**10,133,186**	**-3,672,196**	**(36.24)**						

ENBRIDGE GAS INC.

ACCOUNT 462 - TRANSMISSION PLANT - COMPRESSOR STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011		(21,861)						-21,861	0
2012	1,160,723	(53,618)	-5					-37,740	-7
2013	61,724	2,304	4	-24,392	-6			-24,392	-6
2014	22,375	2,655	12	-16,220	-4			-17,630	-6
2015		0		1,653	6	-14,104	-6	-17,630	-6
2016	3,823.95	(11,720)	-306	-3,022	-35	-12,076	-5	-16,448	-7
2017		(2)		-3,907	-307	-1,353	-8	-13,707	-7
2018	1,677,753	0	0	-3,907	-1	-1,814	-1	-13,707	-3
2019		(289,906)		-96,636	-17	-60,326	-18	-53,164	-13
2020		(290,526)		-193,477	-35	-118,431	-35	-82,834	-23
2021		(291,103)		-290,512	0	-174,307	-52	-105,975	-33
TOTAL	**2,926,399**	**-953,778**	**(32.59)**						

ENBRIDGE GAS INC.

ACCOUNT 463 - TRANSMISSION PLANT - MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010		(680)						-680	0
2011		0						-680	0
2012	26,518	0	0	-227	-3			-680	-3
2013	421	0	0	0	0			-680	-3
2014	52,179	0	0	0	0	-136	-1	-680	-1
2015	103,643	0	0	0	0	0	0	-680	0
2016	3,824	0	0	0	0	0	0	-680	0
2017		5,520		1,840	5	1,104	3	2,420	3
2018	983	0	0	1,840	115	1,104	3	2,420	3
2019	14,845	(17,913)	-121	-4,131	-78	-2,479	-10	-4,358	-6
2020		(19,842)		-12,585	-239	-6,447	-164	-8,229	-16
2021		(19,891)		-19,215	-388	-10,425	-329	-10,561	-26
TOTAL	**202,412**	**-52,806**	**(26.09)**						

ENBRIDGE GAS INC.

ACCOUNT 464 - TRANSMISSION PLANT - EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2012	9,661.55	(4,133)	-43					-4,133	-43
2013		0						-4,133	-43
2014		0		-1,378	-43			-4,133	-43
2015		0		0	0			-4,133	-43
2016		0		0	0	-827	-43	-4,133	-43
2017		0		0	0	0	0	-4,133	-43
2018		0		0	0	0	0	-4,133	-43
2019		(3,172)		-1,057	0	-634	0	-3,652	-76
2020		(4,778)		-2,650	0	-1,590	0	-4,027	-125
2021		(5,223)		-4,391	0	-2,635	0	-4,326	-179
TOTAL	**9,662**	**-17,305**	**(179.11)**						

ENBRIDGE GAS INC.

ACCOUNT 465 - TRANSMISSION PLANT - MAINS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010	446,337	(139,883)	-31					-139,883	-31
2011	22,846	(37,174)	-163					-88,529	-38
2012	10,647	(104,917)	-985	-93,992	-59			-93,992	-59
2013	44,986	(90,534)	-201	-77,542	-296			-93,127	-71
2014	3,639,291	(109,809)	-3	-101,754	-8	-96,464	-12	-96,464	-12
2015	539,695	(54,357)	-10	-84,900	-6	-79,358	-9	-89,446	-11
2016	3,285,511	(339,815)	-10	-167,994	-7	-139,887	-9	-125,213	-11
2017	2,227,274	(1,250,966)	-56	-548,379	-27	-369,096	-19	-265,932	-21
2018	8,337,691	(75,621)	-1	-555,467	-12	-366,114	-10	-244,786	-12
2019		(4,688,331)		-2,004,973	-57	-1,281,818	-45	-689,141	-37
2020	1,935,015	(4,928,975)	-255	-3,230,976	-94	-2,256,742	-71	-1,074,580	-58
2021		(5,148,456)		-4,921,920	-763	-3,218,470	-129	-1,414,070	-83
TOTAL	**20,489,292**	**-16,968,839**	**(82.82)**						

ENBRIDGE GAS INC.

ACCOUNT 466 - TRANSMISSION PLANT - COMPRESSOR EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010	61,532	92,837	151					92,837	0
2011	415,862	(829,015)	-199					-368,089	0
2012	3,785,219	973,053	26	78,958	6			78,958	0
2013	812,316	136,290	17	93,443	6			93,291	0
2014	2,154,337	(31,670)	-1	359,224	16	68,299	5	68,299	0
2015		0		34,873	4	49,732	3	68,299	0
2016	199,097	(682)	0	-10,784	-1	215,398	15	56,802	5
2017	537,959	0	0	-227	0	20,788	3	56,802	4
2018	1,945,218	0	0	-227	0	-6,470	-1	56,802	3
2019		(1,033,363)		-344,454	-42	-206,809	-39	-98,936	-7
2020		(1,035,041)		-689,468	-106	-413,817	-77	-215,949	-17
2021		(1,037,633)		-1,035,346	0	-621,207	-125	-307,247	-28
TOTAL	**9,911,540**	**-2,765,225**	**(27.90)**						

ENBRIDGE GAS INC.

ACCOUNT 467 - TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010	596,725	(151,936)	-25					-151,936	-25
2011	301,202	(304,646)	-101					-228,291	-51
2012	212,181	(15,586)	-7	-157,389	-43			-157,389	-43
2013	3,856,260	(107,918)	-3	-142,717	-10			-145,021	-12
2014	1,231,782	(71,028)	-6	-64,844	-4	-130,223	-11	-130,223	-11
2015	52,902	(66,364)	-125	-81,770	-5	-113,108	-10	-119,580	-11
2016	277,588	(109,723)	-40	-82,372	-16	-74,124	-7	-118,172	-13
2017	57,412	(66,661)	-116	-80,916	-63	-84,339	-8	-111,733	-14
2018	469,437	(259,573)	-55	-145,319	-54	-114,670	-27	-128,159	-16
2019	71,971	(671,290)	-933	-332,508	-167	-234,722	-126	-182,473	-26
2020	10,000	(730,973)	-7,310	-553,946	-301	-367,644	-207	-232,336	-36
2021		(788,253)		-730,172	-2,672	-503,350	-413	-278,663	-47
TOTAL	**7,137,459**	**-3,343,951**	**(46.85)**						

ENBRIDGE GAS INC.

ACCOUNT 472 - DISTRIBUTION PLANT - STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1983	976	125	13					125	13
1984	37,721	0	0					125	0
1985	52,362	150	0	92	0			138	0
1986	108,330	0	0	50	0			138	0
1987	687,595	286,078	42	95,409	34	57,271	32	95,451	32
1988	167,779	0	0	95,359	30	57,246	27	95,451	27
1989	40,157	(317)	-1	95,254	32	57,182	27	71,509	26
1990	150,399	(17,600)	-12	-5,972	-5	53,632	23	53,687	22
1991	2,037,910	(62,612)	-3	-26,843	-4	41,110	7	34,304	6
1992	69,002	(255)	0	-26,822	-4	-16,157	-3	29,367	6
1993	131,064	(114,486)	-87	-59,118	-8	-39,054	-8	11,385	3
1994	13,623	(2,753)	-20	-39,165	-55	-39,541	-8	9,814	3
1995	109,753	(4,365)	-4	-40,535	-48	-36,894	-8	8,396	2
1996	5,307	(3,369)	-63	-3,496	-8	-25,046	-38	7,327	2
1997	2,297	(4,835)	-210	-4,190	-11	-25,962	-50	6,313	2
1998	64,372	(351)	-1	-2,852	-12	-3,135	-8	5,801	2
1999	933,990	51,152	5	15,322	5	7,646	3	9,040	3
2000	4,626,860	58,716	1	36,506	2	20,263	2	12,352	2
2001	673,298	(501,682)	-75	-130,605	-6	-79,400	-6	-19,775	-3
2002	509,884	(44,849)	-9	-162,605	-8	-87,403	-6	-21,250	-3
2003	335,826	195,052	58	-117,159	-23	-48,322	-3	-9,233	-2
2004	88,194	4,752,744	5,389	1,634,316	525	891,996	72	241,397	42
2005	8,601,001	3,404,602	40	2,784,133	93	1,561,174	76	399,557	41
2006	3,047,027	0	0	2,719,116	70	1,661,510	66	399,557	36
2007	1,638,935	(10,902)	-1	1,131,234	26	1,668,299	61	380,012	33
2008	4,806,617	21,805	0	3,634	0	1,633,650	45	363,729	28
2009	701,843	0	0	3,634	0	683,101	18	363,729	27
2010	517,603	(1,488,201)	-288	-488,799	-24	-295,460	-14	283,211	22

ENBRIDGE GAS INC.

ACCOUNT 472 - DISTRIBUTION PLANT - STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	522,803	(1,104,141)	-211	-864,114	-149	-516,288	-32	225,404	18
2012	986,955	(346,230)	-35	-979,524	-145	-583,354	-39	202,539	16
2013	11,676,169	(492,857)	-4	-647,743	-15	-686,286	-24	175,793	11
2014	1,730,751	(1,551,831)	-90	-796,973	-17	-996,652	-32	111,807	7
2015	22,438,068	(11,466,310)	-51	-4,503,666	-38	-2,992,274	-40	-301,697	-13
2016	12,009,265	(12,886)	0	-4,343,676	-36	-2,774,023	-28	-291,738	-11
2017	2,223,298	(1,264)	0	-3,826,820	-31	-2,705,030	-27	-282,056	-10
2018	3,341,502	(9,500)	0	-7,883	0	-2,608,358	-31	-273,264	-10
2019	219,674	154,020	70	47,752	2	-2,267,188	-28	-259,911	-10
2020	32,635	156,718	480	100,413	8	57,418	2	-247,286	-10
2021	38,787,931	161,037	0	157,258	1	92,202	1	-235,276	-6
TOTAL	**124,128,776**	**-7,999,398**	**(6.44)**						

ENBRIDGE GAS INC.

ACCOUNT 473.01 - DISTRIBUTION PLANT - SERVICES - METAL

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1983	1,121,414	(1,406,788)	-125					-1,406,788	-125
1984	900,900	(1,374,074)	-153					-1,390,431	-138
1985	1,038,988	(1,634,307)	-157	-1,471,723	-144			-1,471,723	-144
1986	1,018,346	0	0	-1,002,793	-102			-1,471,723	-108
1987	1,000,246	(2,154,803)	-215	-1,263,037	-124	-1,313,994	-129	-1,642,493	-129
1988	1,360,871	(2,703,445)	-199	-1,619,416	-144	-1,573,326	-148	-1,854,683	-144
1989	2,614,720	(3,145,215)	-120	-2,667,821	-161	-1,927,554	-137	-2,069,772	-137
1990	3,951,440	(3,098,642)	-78	-2,982,434	-113	-2,220,421	-112	-2,216,753	-119
1991	7,058,747	(3,066,654)	-43	-3,103,504	-68	-2,833,752	-89	-2,322,991	-93
1992	9,152,376	(3,347,653)	-37	-3,170,983	-47	-3,072,322	-64	-2,436,842	-75
1993	4,017,731	(3,484,559)	-87	-3,299,622	-49	-3,228,545	-60	-2,541,614	-76
1994	5,705,686	(3,978,739)	-70	-3,603,650	-57	-3,395,249	-57	-2,672,262	-75
1995	7,090,193	(5,296,012)	-75	-4,253,104	-76	-3,834,723	-58	-2,890,908	-75
1996	13,185,410	(5,379,495)	-41	-4,884,749	-56	-4,297,292	-55	-3,082,337	-68
1997	19,126,960	(4,438,032)	-23	-5,037,847	-38	-4,515,368	-46	-3,179,173	-57
1998	9,083,841	(4,202,205)	-46	-4,673,244	-34	-4,658,897	-43	-3,247,375	-56
1999	17,499,760	(4,653,182)	-27	-4,431,139	-29	-4,793,785	-36	-3,335,238	-51
2000	14,964,143	(4,641,399)	-31	-4,498,929	-32	-4,662,863	-32	-3,412,071	-48
2001	32,141,724	(5,628,622)	-18	-4,974,401	-23	-4,712,688	-25	-3,535,213	-42
2002	12,988,609	(6,202,344)	-48	-5,490,788	-27	-5,065,550	-29	-3,675,588	-42
2003	6,560,487	(4,757,942)	-73	-5,529,636	-32	-5,176,698	-31	-3,729,706	-43
2004	14,462,803	(8,429,551)	-58	-6,463,279	-57	-5,931,972	-37	-3,953,508	-45
2005	7,886,238	(4,369,246)	-55	-5,852,246	-61	-5,877,541	-40	-3,972,405	-45
2006	20,787,194	(11,168,196)	-54	-7,988,998	-56	-6,985,456	-56	-4,285,265	-46
2007	12,145,417	(8,770,615)	-72	-8,102,686	-60	-7,499,110	-61	-4,472,155	-47
2008	28,255,673	(7,727,858)	-27	-9,222,223	-45	-8,093,093	-48	-4,602,383	-45
2009	12,078,716	(6,558,026)	-54	-7,685,500	-44	-7,718,788	-48	-4,677,600	-46
2010	29,914,225	(14,385,060)	-48	-9,556,982	-41	-9,721,951	-47	-5,037,136	-46

ENBRIDGE GAS INC.

ACCOUNT 473.01 - DISTRIBUTION PLANT - SERVICES - METAL

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	18,899,412	(5,038,961)	-27	-8,660,682	-43	-8,496,104	-42	-5,037,201	-45
2012	30,682,989	(18,684,533)	-61	-12,702,851	-48	-10,478,888	-44	-5,507,799	-46
2013	10,980,131	(25,825,869)	-235	-16,516,454	-82	-14,098,490	-69	-6,185,068	-52
2014	(1,329,980)	(27,162,032)	2,042	-23,890,811	-178	-18,219,291	-102	-6,861,744	-60
2015	6,133,537	(11,336,424)	-185	-21,441,442	-408	-17,609,564	-135	-7,001,578	-62
2016	4,305,530	(23,390,261)	-543	-20,629,573	-679	-21,279,824	-210	-7,498,204	-67
2017	3,150,738	(3,473,927)	-110	-12,733,537	-281	-18,237,703	-392	-7,379,843	-68
2018	3,645,227	(3,522,946)	-97	-10,129,045	-274	-13,777,118	-433	-7,269,646	-68
2019	3,003,764	(10,317,464)	-343	-5,771,446	-177	-10,408,204	-257	-7,354,308	-70
2020	3,036,881	(7,946,048)	-262	-7,262,153	-225	-9,730,129	-284	-7,370,301	-72
2021	19,429,111	(2,739,701)	-14	-7,001,071	-82	-5,600,017	-87	-7,248,443	-69
TOTAL	**399,050,199**	**-275,440,831**	**(69.02)**						

ENBRIDGE GAS INC.

ACCOUNT 473.02 - DISTRIBUTION PLANT - SERVICES - PLASTIC

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010	1,320,436	(14,385,060)	-1,089	-4,795,020	-1,089	-2,877,012	-1,089	-14,385,060	-1,089
2011	1,059,434	(5,038,961)	-476	-6,474,674	-816	-3,884,804	-816	-9,712,010	-816
2012	3,993,752	(18,684,533)	-468	-12,702,851	-598	-7,621,711	-598	-12,702,851	-598
2013	2,792,085	(25,825,869)	-925	-16,516,454	-632	-12,786,885	-698	-15,983,606	-698
2014	(1,464,971)	(27,162,032)	1,854	-23,890,811	-1,347	-18,219,291	-1,183	-18,219,291	-1,183
2015	7,907,213	(11,336,424)	-143	-21,441,442	-697	-17,609,564	-616	-17,072,147	-656
2016	7,509,388	(23,390,261)	-311	-20,629,573	-444	-21,279,824	-513	-17,974,734	-544
2017	8,040,035	(3,473,927)	-43	-12,733,537	-163	-18,237,703	-368	-16,162,133	-415
2018	8,388,784	(3,522,946)	-42	-10,129,045	-127	-13,777,118	-227	-14,757,779	-336
2019	6,875,256	(10,317,464)	-150	-5,771,446	-74	-10,408,204	-134	-14,313,748	-308
2020	7,814,904	(7,946,048)	-102	-7,262,153	-94	-9,730,129	-126	-13,734,866	-279
2021	42,462,354	(10,899,614)	-26	-9,721,042	-51	-7,232,000	-49	-13,498,595	-168
TOTAL	**96,698,670**	**-161,983,140**	**(167.51)**						

ENBRIDGE GAS INC.

ACCOUNT 475.21 - DISTRIBUTION PLANT - MAINS - COATED AND WRAPPED

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010	4,360,863	(2,317,753)	-53	-772,584	-53	-463,551	-53	-2,317,753	-53
2011	3,346,926	(3,316,737)	-99	-1,878,163	-73	-1,126,898	-73	-2,817,245	-73
2012	7,182,649	(4,065,531)	-57	-3,233,340	-65	-1,940,004	-65	-3,233,340	-65
2013	3,102,447	(7,169,958)	-231	-4,850,742	-107	-3,373,996	-94	-4,217,495	-94
2014	5,287,830	(5,281,427)	-100	-5,505,639	-106	-4,430,281	-95	-4,430,281	-95
2015	4,572,995	(4,992,062)	-109	-5,814,482	-135	-4,965,143	-106	-4,523,911	-97
2016	4,235,834	(14,250,472)	-336	-8,174,654	-174	-7,151,890	-147	-5,913,420	-129
2017	6,847,147	(3,231,587)	-47	-7,491,374	-144	-6,985,101	-145	-5,578,191	-115
2018	8,472,536	(2,725,547)	-32	-6,735,869	-103	-6,096,219	-104	-5,261,230	-100
2019	35,018,160	(13,034,131)	-37	-6,330,422	-38	-7,646,760	-65	-6,038,521	-73
2020	6,416,280	(9,551,132)	-149	-8,436,937	-51	-8,558,574	-70	-6,357,849	-79
2021	72,313,113	(15,051,674)	-21	-12,545,646	-33	-8,718,814	-34	-7,082,334	-53
TOTAL	**156,795,917**	**-82,670,258**	**(52.72)**						

ENBRIDGE GAS INC.

ACCOUNT 475.30 - DISTRIBUTION PLANT - MAINS - PLASTIC

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010	1,600,042	(253,759)						-253,759	-16
2011	1,091,770	(736,219)	-67					-736,219	-67
2012	3,518,233	(777,643)	-22	-589,207	-28			-756,931	-33
2013	1,730,742	(3,037,816)	-176	-1,517,226	-72			-1,517,226	-72
2014	1,690,219	(2,391,039)	-141	-2,068,833	-89	-1,439,295	-75	-1,735,679	-86
2015	1,384,802	(3,293,466)	-238	-2,907,440	-181	-2,047,237	-109	-2,047,237	-109
2016	1,607,232	(9,950,554)	-619	-5,211,686	-334	-3,890,104	-196	-3,364,456	-183
2017	1,119,340	(319,190)	-29	-4,521,070	-330	-3,798,413	-252	-2,929,418	-169
2018	1,345,339	(313,743)	-23	-3,527,829	-260	-3,253,598	-228	-2,602,459	-154
2019	19,516,000	(6,077,664)	-31	-2,236,866	-31	-3,990,923	-80	-2,988,593	-81
2020	827,810	(5,819,891)	-703	-4,070,433	-56	-4,496,208	-92	-3,271,723	-97
2021	137,226,724	(6,724,317)	-5	-6,207,291	-12	-3,850,961	-12	-3,585,595	-23
TOTAL	**171,058,212**	**-39,441,543**	**(23.06)**						

ENBRIDGE GAS INC.

ACCOUNT 477 - DISTRIBUTION PLANT - MEASURING AND REGULATING EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1983	314,469	(6,278)	-2					-6,278	-2
1984	468,427	(4,583)	-1					-5,431	-1
1985	1,156,467	(18,215)	-2	-9,692	-1			-9,692	-1
1986	457,050	0	0	-7,599	-1			-9,692	-1
1987	406,322	5,352	1	-4,288	-1	-4,745	-1	-5,931	-1
1988	523,769	6,347	1	3,900	1	-2,220	0	-3,476	-1
1989	700,673	150,000	21	53,900	10	28,697	4	22,104	3
1990	810,141	42,101	5	66,149	10	40,760	7	24,960	4
1991	765,922	97,105	13	96,402	13	60,181	9	33,979	5
1992	1,353,850	(51,769)	-4	29,146	3	48,757	6	24,451	3
1993	1,421,708	(104,600)	-7	-19,755	-2	26,567	3	11,546	1
1994	1,194,077	(198,158)	-17	-118,176	-9	-43,064	-4	-7,518	-1
1995	2,231,130	(73,271)	-3	-125,343	-8	-66,139	-5	-12,997	-1
1996	1,952,020	(402,757)	-21	-224,729	-13	-166,111	-10	-42,979	-4
1997	3,191,208	(398,985)	-13	-291,671	-12	-235,554	-12	-68,408	-6
1998	69,261	(952,473)	-1,375	-584,739	-34	-405,129	-23	-127,346	-11
1999	1,342,147	(1,008,467)	-75	-786,642	-51	-567,191	-32	-182,416	-16
2000	990,198	(777,577)	-79	-912,839	-114	-708,052	-47	-217,425	-19
2001	1,682,625	(809,092)	-48	-865,045	-65	-789,319	-54	-250,296	-21
2002	992,861	(259,128)	-26	-615,265	-50	-761,347	-75	-250,760	-22
2003	848,264	121,864	14	-315,452	-27	-546,480	-47	-232,129	-20
2004	6,269,144	(186,235)	-3	-107,833	-4	-382,033	-18	-229,944	-17
2005	1,475,555	0	0	-21,457	-1	-226,518	-10	-229,944	-16
2006	1,296,683	0	0	-62,078	-2	-64,700	-3	-229,944	-15
2007	89,461	0	0	0	0	-12,874	-1	-229,944	-15
2008	261,348	0	0	0	0	-37,247	-2	-229,944	-15
2009	5,194,456	0	0	0	0	0	0	-229,944	-13
2010	2,060,713	(228,960)	-11	-76,320	-3	-45,792	-3	-229,899	-13

ENBRIDGE GAS INC.

ACCOUNT 477 - DISTRIBUTION PLANT - MEASURING AND REGULATING EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	1,029,157	(383,142)	-37	-204,034	-7	-122,420	-7	-236,562	-13
2012	649,983	(678,791)	-104	-430,298	-35	-258,179	-14	-254,988	-15
2013	4,688,356	(715,899)	-15	-592,611	-28	-401,358	-15	-273,424	-15
2014	2,062,985	(1,429,702)	-69	-941,464	-38	-687,299	-33	-317,897	-17
2015	2,038,582	(1,242,444)	-61	-1,129,348	-39	-889,995	-43	-352,139	-19
2016	265,070	(2,449,195)	-924	-1,707,113	-117	-1,303,206	-67	-427,034	-24
2017	2,471,148	(247,538)	-10	-1,313,059	-82	-1,216,956	-53	-420,844	-23
2018	2,622,838	(82,005)	-3	-926,246	-52	-1,090,177	-58	-409,550	-22
2019	1,744,325	(2,369,433)	-136	-899,659	-39	-1,278,123	-70	-472,772	-26
2020	3,203,912	(2,112,086)	-66	-1,521,175	-60	-1,452,051	-70	-524,000	-28
2021	18,566,278	(2,795,001)	-15	-2,425,507	-31	-1,521,213	-27	-592,819	-25
TOTAL	**78,862,581**	**-19,563,014**	**(24.81)**						

ENBRIDGE GAS INC.

ACCOUNT 478 - DISTRIBUTION PLANT - METERS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1983	670,210	34,920	5					34,920	5
1984	765,326	39,369	5					37,145	5
1985	853,325	33,120	4	35,803	5			35,803	5
1986	1,177,249	0	0	24,163	3			35,803	3
1987	955,593	27,690	3	20,270	2	27,020	3	33,775	3
1988	1,067,020	16,517	2	14,736	1	23,339	2	30,323	3
1989	1,078,230	25,007	2	23,071	2	20,467	2	29,437	3
1990	1,123,930	9,131	1	16,885	2	15,669	1	26,536	2
1991	1,460,870	4,096	0	12,745	1	16,488	1	23,731	2
1992	1,225,334	(2,872)	0	3,452	0	10,376	1	20,775	2
1993	1,139,656	(547)	0	226	0	6,963	1	18,643	2
1994	1,467,536	(484)	0	-1,301	0	1,865	0	16,904	1
1995	2,012,823	5,069	0	1,346	0	1,052	0	15,918	1
1996	1,285,120	(4,810)	0	-75	0	-729	0	14,324	1
1997	2,358,960	0	0	86	0	-154	0	14,324	1
1998	1,931,633	0	0	-1,603	0	-45	0	14,324	1
1999	1,599,321	0	0	0	0	52	0	14,324	1
2000	1,079,952	(38,478)	-4	-12,826	-1	-8,658	-1	10,552	1
2001	871,574	2,996	0	-11,827	-1	-7,096	0	10,048	1
2002	1,388,920	104,170	8	22,896	2	13,738	1	15,931	1
2003	1,076,445	0	0	35,722	3	13,738	1	15,931	1
2004	1,580,824	237,304	15	113,825	8	61,199	5	28,953	2
2005	1,839,783	108,205	6	115,170	8	90,535	7	33,356	2
2006	2,398,725	122,933	5	156,147	8	114,522	7	38,070	2
2007	5,021,259	315,314	6	182,151	6	156,751	7	51,933	3
2008	5,092,128	346,804	7	261,684	6	226,112	7	65,974	3
2009	235	345,090	146,847	335,736	10	247,669	9	78,661	4
2010	19,278,850	459,074	2	383,656	5	317,843	5	95,201	4

ENBRIDGE GAS INC.

ACCOUNT 478 - DISTRIBUTION PLANT - METERS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	12,955,756	2,328,517	18	1,044,227	10	758,960	9	188,256	6
2012	16,809,624	1,133,513	7	1,307,035	8	922,600	9	226,066	6
2013	20,311,080	1,359,033	7	1,607,021	10	1,125,045	8	269,642	6
2014	19,854,175	750,439	4	1,080,995	6	1,206,115	7	287,449	6
2015	26,372,835	1,176,552	4	1,095,341	5	1,349,611	7	319,203	6
2016	21,421,742	(1,757,513)	-8	56,492	0	532,405	3	247,592	4
2017	33,916,533	447,159	1	-44,601	0	395,134	2	254,244	4
2018	17,550,530	343,326	2	-322,343	-1	191,992	1	257,118	3
2019	16,923,831	203,978	1	331,487	1	82,700	0	255,457	3
2020	5,618,593	55,048	1	200,784	2	-141,601	-1	249,384	3
2021	150,951,920	117,013	0	125,346	0	233,305	1	245,491	2
TOTAL	**404,487,450**	**8,346,683**	**2.06**						

ENBRIDGE GAS INC.

ACCOUNT 482 - GENERAL PLANT - STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	44,920	(4,179)	-9					-4,179	-9
2012		(6,240)						-5,210	-23
2013	2,077,170	(14,000)	-1	-8,140	-1			-8,140	-1
2014	91,193	988	1	-6,417	-1			-5,858	-1
2015	6,190,458	0	0	-4,337	0	-4,686	0	-5,858	0
2016	253,237	0	0	329	0	-3,850	0	-5,858	0
2017	1,731,459	0	0	0	0	-2,602	0	-5,858	0
2018	523,596	0	0	0	0	198	0	-5,858	0
2019		309,595		103,198	14	61,919	4	57,233	3
2020	301,103	534,241	177	281,279	102	168,767	30	136,734	7
2021	6,242,911	347,347	6	397,061	18	238,237	14	166,822	7
TOTAL	**17,456,047**	**1,167,752**	**6.69**						

ENBRIDGE GAS INC.

ACCOUNT 484 - GENERAL PLANT - TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1983	116,442	15,332	13					15,332	13
1984	301,546	16,023	5					15,678	8
1985	230,327	40,375	18	23,910	11			23,910	11
1986	295,483	0	0	18,799	7			23,910	8
1987	132,359	28,644	22	23,006	10	20,075	9	25,094	9
1988	287,345	29,765	10	19,470	8	22,961	9	26,028	10
1989	143,302	19,543	14	25,984	14	23,665	11	24,947	10
1990	493,837	37,625	8	28,978	9	23,115	9	26,758	9
1991	527,161	66,176	13	41,115	11	36,351	11	31,685	10
1992	608,025	0	0	34,600	6	30,622	7	31,685	8
1993	229,798	42,031	18	36,069	8	33,075	8	32,835	9
1994	462,320	21,266	5	21,099	5	33,420	7	31,678	8
1995	486,358	56,788	12	40,028	10	37,252	8	33,961	9
1996	499,604	87,017	17	55,024	11	41,420	9	38,382	10
1997	525,616	118,749	23	87,518	17	65,170	15	44,564	11
1998	360,363	135,746	38	113,837	25	83,913	18	51,077	13
1999	1,024,849	60,295	6	104,930	16	91,719	16	51,692	12
2000	270,661	94,294	35	96,778	18	99,220	19	54,354	12
2001	700,215	42,064	6	65,551	10	90,229	16	53,631	12
2002	907,470	84,446	9	73,601	12	83,369	13	55,343	12
2003	467,721	0	0	42,170	6	56,220	8	55,343	11
2004	148,334	76,600	52	53,682	11	59,481	12	56,462	12
2005	163,189	12,910	8	29,837	11	43,204	9	54,284	12
2006	806,168	142,966	18	77,492	21	63,384	13	58,507	12
2007	242,174	(47,049)	-19	36,276	9	37,085	10	53,709	11
2008	1,407,043	150,988	11	82,302	10	67,283	12	57,939	11
2009	2,777,760	290,232	10	131,391	9	110,010	10	67,618	11
2010	2,299,171	369,554	16	270,258	13	181,338	12	79,695	12

ENBRIDGE GAS INC.

ACCOUNT 484 - GENERAL PLANT - TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	3,705,395	887,631	24	515,806	18	330,271	16	110,770	14
2012	8,247,578	734,708	9	663,964	14	486,623	13	133,879	13
2013	4,424,238	1,026,822	23	883,054	16	661,790	15	165,769	14
2014	5,740,450	658,310	11	806,613	13	735,405	15	182,754	14
2015	11,842,442	472,885	4	719,339	10	756,071	11	192,425	11
2016	9,488,153	(415,513)	-4	238,561	3	495,442	6	172,814	9
2017	6,296,029	687,926	11	248,432	3	486,086	6	188,911	9
2018	5,777,851	804,697	14	359,036	5	441,661	6	207,571	9
2019	8,053,271	1,463,770	18	985,464	15	602,753	7	244,518	10
2020	6,335,392	790,534	12	1,019,667	15	666,283	9	260,119	10
2021	38,843,393	1,563,608	4	1,272,637	7	1,062,107	8	296,327	8
TOTAL	**125,668,832**	**10,667,758**	**8.49**						

ENBRIDGE GAS INC.

ACCOUNT 485 - GENERAL PLANT - HEAVY WORK EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1983	145,955	2,400	2					2,400	2
1984	223,250	128,699	58					65,550	36
1985	186,060	37,050	20	56,050	30			56,050	30
1986	153,575	0	0	55,250	29			56,050	24
1987	254,972	113,052	44	50,034	25	56,240	29	70,300	29
1988	300,933	66,010	22	59,687	25	68,962	31	69,442	27
1989	362,095	83,480	23	87,514	29	59,918	24	71,782	26
1990	260,722	116,503	45	88,665	29	75,809	28	78,171	29
1991	73,098	23,680	32	74,554	32	80,545	32	71,359	29
1992	396,128	106,481	27	82,221	34	79,231	28	75,262	29
1993	209,696	60,327	29	63,496	28	78,094	30	73,768	29
1994	377,497	23,435	6	63,414	19	66,085	25	69,192	26
1995	481,619	23,000	5	35,587	10	47,385	15	65,343	23
1996	400,121	121,614	30	56,016	13	66,971	18	69,672	24
1997	228,184	18,050	8	54,221	15	49,285	15	65,984	23
1998	121,172	163,567	135	101,077	40	69,933	22	72,490	26
1999	347,016	16,296	5	65,971	28	68,505	22	68,978	24
2000		(2,502)		59,120	38	63,405	29	64,773	24
2001	307,248	167,956	55	60,583	28	72,673	36	70,505	26
2002	199,154	20,322	10	61,925	37	73,128	38	67,864	26
2003	236,474	104,000	44	97,426	39	61,214	28	69,671	26
2004	151,628	10,500	7	44,941	23	60,055	34	66,853	26
2005	287,014	60,241	21	58,247	26	72,604	31	66,553	26
2006	207,422	57,376	28	42,706	20	50,488	23	66,154	26
2007	72,900	69,376	95	62,331	33	60,299	32	66,288	27
2008	157,107	18,150	12	48,301	33	43,129	25	64,362	26
2009	545,012	170,549	31	86,025	33	75,138	30	68,447	27
2010	1,100,046	113,778	10	100,825	17	85,846	21	70,125	24

ENBRIDGE GAS INC.

ACCOUNT 485 - GENERAL PLANT - HEAVY WORK EQUIPMENT

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2011	2,617,303	366,984	14	217,103	15	147,767	16	80,728	22
2012	1,818,811	0	0	160,254	9	133,892	11	80,728	18
2013	2,811,973	574,256	20	313,747	13	245,113	14	97,746	19
2014	852,916	34,351	4	202,869	11	217,874	12	95,633	18
2015	4,631,477	0	0	202,869	7	195,118	8	95,633	14
2016	1,602,277	(142,759)	-9	-36,136	-2	93,169	4	87,943	12
2017	945,203	228,014	24	28,418	1	138,772	6	92,320	13
2018	404,046	91,075	23	58,776	6	42,136	2	92,282	13
2019	1,343,097	264,866	20	194,651	22	88,239	5	97,358	13
2020	1,202,379	54,443	5	136,794	14	99,127	9	96,132	13
2021	7,088,407	49,856	1	123,055	4	137,651	6	94,846	10
TOTAL	**33,103,986**	**3,414,472**	**10.31**						

8 DETAILED DEPRECIATION CALCULATIONS

Enbridge Gas Distribution

Account #: 442.00 - Local Storage - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S5
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1970	1,422,484.91	1,384,968	1,422,485	1.0000	0	1.40	0	51.5
1998	437,097.64	260,528	368,417	0.8429	68,680	15.93	4,312	23.5
2001	19,303.59	10,038	14,194	0.7353	5,109	18.92	270	20.5
2005	181,728.66	76,059	107,556	0.5919	74,172	22.92	3,236	16.5
2006	238,393.02	93,728	132,542	0.5560	105,851	23.92	4,425	15.5
2007	128,007.31	47,081	66,578	0.5201	61,429	24.92	2,465	14.5
2008	24,939.54	8,540	12,077	0.4842	12,863	25.92	496	13.5
2009	10,061.95	3,190	4,512	0.4484	5,550	26.92	206	12.5
2010	163,888.91	47,807	67,605	0.4125	96,284	27.92	3,448	11.5
2011	311,493.59	82,962	117,319	0.3766	194,175	28.92	6,713	10.5
2012	631,185.96	152,098	215,085	0.3408	416,101	29.92	13,905	9.5
2013	75,000.00	16,170	22,867	0.3049	52,133	30.92	1,686	8.5
2014	158,244.04	30,104	42,571	0.2690	115,673	31.92	3,623	7.5
2015	271,535.48	44,770	63,309	0.2332	208,226	32.92	6,325	6.5
2016	100,162.81	13,974	19,760	0.1973	80,402	33.92	2,370	5.5
2017	480,616.37	54,860	77,578	0.1614	403,038	34.92	11,541	4.5
2018	35,418.39	3,144	4,447	0.1255	30,972	35.92	862	3.5
2019	47,004.66	2,981	4,215	0.0897	42,790	36.92	1,159	2.5
2020	396,502.45	15,086	21,334	0.0538	375,169	37.92	9,893	1.5
2021	1,149,111.81	14,574	20,609	0.0179	1,128,503	38.92	28,993	0.5

Enbridge Gas Distribution

Account #: 442.00 - Local Storage - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S5
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	6,282,181.09	2,362,662	2,805,060		3,477,121		105,927	

COMPOSITE ANNUAL ACCRUAL RATE	1.69%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.45
COMPOSITE AVERAGE AGE (YEARS)	17.80
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	24.68

Enbridge Gas Inc.

Account #: 443.01 - Local Storage - Holder Storage Tank

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 45
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1969	2,186,400.39	2,040,876	2,186,400	1.0000	0	3.74	0	52.5
1999	2,066,786.98	1,063,930	1,593,173	0.7708	473,614	21.21	22,331	22.5
2002	320,890.28	144,537	216,436	0.6745	104,455	23.79	4,390	19.5
2016	24,428.41	3,167	4,742	0.1941	19,686	36.92	533	5.5
2017	10,174.29	1,080	1,617	0.1589	8,557	37.90	226	4.5
2021	1,195,732.11	14,141	21,176	0.0177	1,174,557	41.78	28,114	0.5
TOTAL	5,804,412.46	3,267,731	4,023,544		1,780,869		55,595	

COMPOSITE ANNUAL ACCRUAL RATE	0.96%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	29.00
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	19.11

Enbridge Gas Inc.

Account #: 443.02 - Local Storage - Holder Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1972	995,702.37	823,496	995,702	1.0000	0	10.35	0	49.5
1973	2,781,547.11	2,269,885	2,781,547	1.0000	0	10.93	0	48.5
1999	926,089.18	394,930	905,285	0.9775	20,804	30.26	687	22.5
2000	131,835.31	53,828	123,388	0.9359	8,447	31.16	271	21.5
2001	652,044.40	254,303	582,929	0.8940	69,115	32.06	2,156	20.5
2002	721,508.49	268,112	614,583	0.8518	106,925	32.98	3,243	19.5
2004	45,184.84	15,112	34,642	0.7667	10,543	34.82	303	17.5
2006	2,174,475.26	645,719	1,480,159	0.6807	694,316	36.70	18,920	15.5
2007	49,625.58	13,800	31,634	0.6375	17,992	37.64	478	14.5
2009	19,777.96	4,750	10,888	0.5505	8,890	39.55	225	12.5
2010	1,191,154.34	263,402	603,787	0.5069	587,367	40.51	14,501	11.5
2011	92,079.93	18,605	42,647	0.4631	49,433	41.47	1,192	10.5
2012	155,062.30	28,365	65,020	0.4193	90,042	42.43	2,122	9.5
2013	4,038,394.78	661,366	1,516,026	0.3754	2,522,369	43.40	58,116	8.5
2014	2,150,515.09	310,929	712,731	0.3314	1,437,784	44.37	32,402	7.5
2015	33,284.24	4,173	9,565	0.2874	23,719	45.35	523	6.5
2016	1,462,777.95	155,253	355,881	0.2433	1,106,897	46.32	23,896	5.5
2017	1,912,619.22	166,167	380,899	0.1992	1,531,720	47.30	32,386	4.5
2018	468,290.69	31,659	72,570	0.1550	395,720	48.27	8,198	3.5
2020	204,701.33	5,937	13,610	0.0665	191,091	50.21	3,806	1.5
2021	1,347,851.56	13,044	29,900	0.0222	1,317,952	51.17	25,758	0.5

Enbridge Gas Inc.

Account #: 443.02 - Local Storage - Holder Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	21,554,521.93	6,402,834	11,363,396		10,191,126		229,183	

COMPOSITE ANNUAL ACCRUAL RATE	1.06%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.53
COMPOSITE AVERAGE AGE (YEARS)	16.56
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	36.77

Enbridge Gas Inc.

Account #: 451.00 - Underground Storage - Land Rights Intangible

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life

Survivor Curve: R4

ASL: 55

Net Salvage: 0%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1963	2,261,925.37	2,043,177	2,261,925	1.0000	0	6.26	0	58.5
1964	5,277,825.12	4,733,202	5,277,825	1.0000	0	6.62	0	57.5
1977	5,954,998.00	4,577,298	5,954,998	1.0000	0	13.39	0	44.5
1980	9,015.54	6,582	9,016	1.0000	0	15.35	0	41.5
1985	3,140.39	2,071	3,140	1.0000	0	18.84	0	36.5
1987	15,973,398.04	10,051,789	10,843,286	0.6788	5,130,112	20.32	252,413	34.5
1988	1,286,979.22	789,831	789,831	0.6137	497,148	21.09	23,577	33.5
1989	8,575,503.16	5,126,885	5,126,885	0.5979	3,448,619	21.86	157,750	32.5
1990	48.07	28	28	0.5817	20	22.65	1	31.5
1991	669,059.25	378,246	378,246	0.5653	290,814	23.45	12,401	30.5
1992	8,978.82	4,927	4,927	0.5487	4,052	24.26	167	29.5
1993	121,226.62	64,475	64,475	0.5319	56,752	25.09	2,262	28.5
1994	10,678,770.77	5,497,120	5,497,120	0.5148	5,181,651	25.92	199,895	27.5
1995	1,101,907.25	548,167	548,167	0.4975	553,741	26.77	20,686	26.5
1996	328,719.73	157,778	157,778	0.4800	170,942	27.63	6,187	25.5
1997	3,644,584.07	1,684,890	1,684,890	0.4623	1,959,694	28.50	68,771	24.5
1998	223,055.00	99,138	99,138	0.4445	123,917	29.37	4,219	23.5
1999	7,485,409.72	3,192,150	3,192,150	0.4264	4,293,260	30.26	141,873	22.5
2000	1,870,824.89	763,852	763,852	0.4083	1,106,973	31.16	35,528	21.5
2001	6,208,891.29	2,421,519	2,421,519	0.3900	3,787,373	32.06	118,123	20.5
2002	1,069,691.48	397,496	397,496	0.3716	672,195	32.98	20,384	19.5
2004	132,863.75	44,437	44,437	0.3345	88,426	34.82	2,539	17.5
2007	1,028.50	286	286	0.2781	742	37.64	20	14.5
2012	850,377.64	155,556	155,556	0.1829	694,822	42.43	16,374	9.5
2013	949,494.20	155,498	155,498	0.1638	793,996	43.40	18,294	8.5
2015	74,637.71	9,357	9,357	0.1254	65,280	45.35	1,440	6.5

Enbridge Gas Inc.

Account #: 451.00 - Underground Storage - Land Rights Intangible
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	74,762,353.60	42,905,753	45,841,825		28,920,529		1,102,905	

COMPOSITE ANNUAL ACCRUAL RATE	1.48%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.61
COMPOSITE AVERAGE AGE (YEARS)	32.10
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	22.97

Enbridge Gas Distribution

Account #: 452.00 - Underground Storage - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1950	1,443,865.83	1,588,252	1,381,686	0.8699	206,566	0.00	206,566	71.5
1952	1,104,878.64	1,215,367	1,057,298	0.8699	158,069	0.00	158,069	69.5
1954	3,098,356.05	3,383,131	2,943,126	0.8635	465,066	0.50	465,066	67.5
1962	8,198.33	8,731	7,595	0.8422	1,423	1.96	727	59.5
1964	161,209.98	170,111	147,987	0.8345	29,344	2.44	12,025	57.5
1966	257.28	269	234	0.8264	49	2.92	17	55.5
1967	38,330.34	39,852	34,669	0.8222	7,495	3.16	2,371	54.5
1969	2,925.44	3,009	2,618	0.8135	600	3.64	165	52.5
1971	97,662.36	99,312	86,396	0.8042	21,033	4.13	5,096	50.5
1972	573,998.86	580,067	504,625	0.7992	126,774	4.38	28,942	49.5
1973	396,639.47	398,187	346,400	0.7939	89,904	4.64	19,365	48.5
1975	84,377.94	83,475	72,618	0.7824	20,197	5.20	3,882	46.5
1976	159,360.99	156,376	136,038	0.7760	39,259	5.51	7,131	45.5
1978	1,112,793.54	1,072,221	932,769	0.7620	291,304	6.16	47,285	43.5
1979	48,559.20	46,314	40,291	0.7543	13,124	6.52	2,014	42.5
1980	45,811.13	43,216	37,595	0.7461	12,797	6.89	1,857	41.5
1981	459,112.06	428,018	372,351	0.7373	132,672	7.29	18,208	40.5
1982	126,906.21	116,819	101,626	0.7280	37,971	7.70	4,930	39.5
1983	637,075.20	578,504	503,264	0.7181	197,519	8.14	24,272	38.5
1984	12,356.58	11,058	9,620	0.7077	3,972	8.59	462	37.5
1985	6,398,911.12	5,637,851	4,904,600	0.6968	2,134,202	9.07	235,306	36.5
1986	585,015.27	506,929	440,999	0.6853	202,518	9.57	21,172	35.5
1987	23,832.05	20,288	17,649	0.6733	8,566	10.08	850	34.5
1988	438,389.99	366,229	318,598	0.6607	163,631	10.61	15,421	33.5
1989	7,175,283.09	5,875,373	5,111,230	0.6476	2,781,582	11.16	249,255	32.5
1990	384,531.97	308,252	268,162	0.6340	154,824	11.72	13,205	31.5

Enbridge Gas Distribution

Account #: 452.00 - Underground Storage - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	10,690,648.49	8,379,306	7,289,504	0.6199	4,470,209	12.30	363,301	30.5
1992	1,442,301.45	1,103,871	960,303	0.6053	626,228	12.90	48,550	29.5
1993	4,619,528.91	3,447,627	2,999,233	0.5902	2,082,249	13.51	154,168	28.5
1994	1,045,497.63	759,761	660,947	0.5747	489,100	14.13	34,622	27.5
1995	1,766,850.15	1,248,303	1,085,951	0.5588	857,584	14.76	58,106	26.5
1996	694,194.79	476,062	414,146	0.5424	349,468	15.40	22,689	25.5
1997	3,980,697.34	2,645,160	2,301,134	0.5255	2,077,633	16.06	129,391	24.5
1998	1,097,522.69	705,361	613,623	0.5083	593,652	16.72	35,502	23.5
1999	356,921.57	221,416	192,619	0.4906	199,995	17.40	11,496	22.5
2000	437,532.69	261,425	227,425	0.4725	253,861	18.08	14,040	21.5
2001	262,245.39	150,566	130,983	0.4541	157,487	18.78	8,388	20.5
2002	32,408.17	17,834	15,514	0.4352	20,135	19.48	1,034	19.5
2003	52,561.38	27,644	24,048	0.4159	33,769	20.19	1,672	18.5
2004	5,134.95	2,573	2,238	0.3963	3,410	20.92	163	17.5
2005	120,335.65	57,255	49,808	0.3763	82,561	21.65	3,814	16.5
2006	6,134,325.97	2,760,596	2,401,556	0.3559	4,346,202	22.39	194,141	15.5
2007	165,148.76	69,990	60,888	0.3352	120,776	23.14	5,220	14.5
2008	2,022,148.64	803,076	698,629	0.3141	1,525,734	23.89	63,859	13.5
2009	1,127,927.98	417,391	363,105	0.2927	877,615	24.66	35,593	12.5
2010	3,231,053.01	1,106,792	962,844	0.2709	2,591,314	25.43	101,904	11.5
2011	2,648,624.28	833,381	724,993	0.2488	2,188,494	26.21	83,505	10.5
2012	3,093,659.63	885,905	770,685	0.2265	2,632,341	26.99	97,522	9.5
2013	448,471.88	115,574	100,542	0.2038	392,777	27.78	14,138	8.5
2014	2,896,331.69	662,376	576,229	0.1809	2,609,736	28.57	91,332	7.5
2015	860,535.48	171,540	149,230	0.1577	797,359	29.37	27,150	6.5
2016	15,595,267.55	2,645,826	2,301,713	0.1342	14,853,081	30.16	492,469	5.5

Enbridge Gas Distribution

Account #: 452.00 - Underground Storage - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	7,302,384.67	1,019,750	887,123	0.1104	7,145,500	30.95	230,897	4.5
2018	2,833,242.95	309,716	269,435	0.0865	2,847,133	31.72	89,760	3.5
2019	953,462.49	74,993	65,239	0.0622	983,569	32.46	30,298	2.5
2020	497,356.37	23,688	20,607	0.0377	526,485	33.14	15,885	1.5
2021	3,400,858.77	54,824	47,694	0.0127	3,693,251	33.62	109,861	0.5
TOTAL	104,433,820.29	54,196,797	47,148,032		67,729,170		4,114,127	

COMPOSITE ANNUAL ACCRUAL RATE 3.94%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.45

COMPOSITE AVERAGE AGE (YEARS) 21.28

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 19.81

Enbridge Gas Distribution

Account #: 453.00 - Underground Storage - Wells

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1930	104,556.07	135,923	106,840	0.7860	29,083	0.00	29,083	91.5
1944	136,898.18	175,477	137,931	0.7750	40,036	1.10	36,402	77.5
1948	199,945.48	251,053	197,336	0.7592	62,593	2.60	24,086	73.5
1951	93,734.88	116,427	91,515	0.7510	30,340	3.29	9,230	70.5
1952	77,656.86	96,119	75,553	0.7484	25,401	3.50	7,266	69.5
1953	134,260.49	165,592	130,161	0.7457	44,378	3.70	11,991	68.5
1954	624,444.06	767,381	603,188	0.7430	208,589	3.91	53,414	67.5
1955	821,267.15	1,005,566	790,409	0.7403	277,238	4.11	67,527	66.5
1957	668,745.36	812,498	638,652	0.7346	230,717	4.51	51,104	64.5
1959	213,743.90	257,541	202,436	0.7285	75,431	4.93	15,292	62.5
1960	56,120.82	67,326	52,920	0.7254	20,037	5.14	3,895	61.5
1962	77,124.21	91,666	72,053	0.7187	28,209	5.58	5,056	59.5
1963	154,668.29	182,923	143,783	0.7151	57,285	5.80	9,871	58.5
1964	383,488.89	451,208	354,665	0.7114	143,871	6.03	23,854	57.5
1965	34,719.32	40,629	31,936	0.7076	13,199	6.27	2,106	56.5
1966	297,332.41	345,949	271,928	0.7035	114,604	6.51	17,603	55.5
1968	152,156.75	174,837	137,428	0.6948	60,376	7.03	8,591	53.5
1969	349,341.25	398,683	313,379	0.6900	140,765	7.30	19,274	52.5
1970	247,704.72	280,645	220,597	0.6850	101,419	7.59	13,359	51.5
1971	1,817,702.23	2,043,557	1,606,306	0.6798	756,707	7.89	95,855	50.5
1972	181,715.80	202,618	159,265	0.6742	76,965	8.21	9,373	49.5
1973	112,820.71	124,699	98,018	0.6683	48,649	8.54	5,694	48.5
1974	662,545.00	725,491	570,261	0.6621	291,048	8.89	32,730	47.5
1975	182,511.82	197,874	155,536	0.6555	81,729	9.26	8,829	46.5
1976	56,281.42	60,377	47,459	0.6486	25,707	9.64	2,667	45.5
1977	1,081,721.94	1,147,489	901,966	0.6414	504,273	10.03	50,254	44.5

Enbridge Gas Distribution

Account #: 453.00 - Underground Storage - Wells

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1978	289,304.67	303,259	238,372	0.6338	137,724	10.45	13,182	43.5
1979	43,794.73	45,331	35,632	0.6259	21,301	10.88	1,958	42.5
1980	129,253.29	132,014	103,768	0.6176	64,262	11.32	5,676	41.5
1981	98,176.70	98,869	77,714	0.6089	49,915	11.78	4,237	40.5
1983	952,280.58	930,071	731,068	0.5905	506,897	12.75	39,772	38.5
1984	993,563.17	954,462	750,240	0.5808	541,393	13.25	40,869	37.5
1985	574,551.17	542,411	426,354	0.5708	320,563	13.76	23,294	36.5
1986	1,017,908.12	943,520	741,639	0.5605	581,641	14.29	40,707	35.5
1987	2,631,509.87	2,392,665	1,880,717	0.5498	1,540,246	14.83	103,880	34.5
1988	3,063,744.82	2,729,881	2,145,780	0.5388	1,837,088	15.38	119,476	33.5
1989	2,374,634.32	2,071,399	1,628,191	0.5274	1,458,834	15.94	91,549	32.5
1990	4,135,719.57	3,528,053	2,773,171	0.5158	2,603,265	16.50	157,743	31.5
1991	367,365.07	306,130	240,629	0.5039	236,946	17.08	13,872	30.5
1992	2,201,348.50	1,789,841	1,406,876	0.4916	1,454,877	17.67	82,349	29.5
1993	2,048,868.33	1,623,380	1,276,032	0.4791	1,387,496	18.26	75,982	28.5
1994	465,393.09	358,870	282,084	0.4662	322,927	18.86	17,121	27.5
1995	5,219,871.28	3,911,800	3,074,809	0.4531	3,711,023	19.47	190,604	26.5
1996	5,086,168.60	3,698,744	2,907,340	0.4397	3,704,679	20.08	184,452	25.5
1997	4,591,763.32	3,235,157	2,542,944	0.4260	3,426,348	20.71	165,478	24.5
1998	1,035,895.06	705,889	554,853	0.4120	791,810	21.33	37,118	23.5
1999	2,881,468.81	1,895,535	1,489,956	0.3978	2,255,954	21.96	102,712	22.5
2000	622,877.47	394,757	310,293	0.3832	499,448	22.60	22,098	21.5
2001	535,710.55	326,372	256,540	0.3684	439,884	23.24	18,925	20.5
2002	10,342,747.47	6,042,674	4,749,750	0.3533	8,695,822	23.89	364,002	19.5
2003	1,109,439.29	619,952	487,303	0.3379	954,968	24.54	38,917	18.5
2004	452,253.93	241,002	189,436	0.3222	398,494	25.19	15,818	17.5

Enbridge Gas Distribution

Account #: 453.00 - Underground Storage - Wells

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2005	1,360,580.25	689,168	541,710	0.3063	1,227,044	25.85	47,473	16.5
2006	996,980.51	478,262	375,931	0.2901	920,144	26.50	34,717	15.5
2007	571,778.84	258,700	203,347	0.2736	539,965	27.16	19,879	14.5
2008	1,208,898.37	513,466	403,602	0.2568	1,167,966	27.82	41,984	13.5
2009	1,775,954.26	704,289	553,595	0.2398	1,755,145	28.48	61,635	12.5
2010	11,625,733.52	4,277,734	3,362,446	0.2225	11,751,008	29.13	403,398	11.5
2011	926,645.91	314,031	246,839	0.2049	957,800	29.78	32,164	10.5
2012	3,611,156.89	1,117,196	878,154	0.1871	3,816,350	30.42	125,458	9.5
2013	1,210,191.93	338,119	265,773	0.1689	1,307,477	31.05	42,109	8.5
2014	2,286,760.05	569,263	447,460	0.1505	2,525,328	31.67	79,748	7.5
2015	2,024,005.52	441,236	346,827	0.1318	2,284,380	32.26	70,809	6.5
2016	7,066,060.81	1,318,234	1,036,177	0.1128	8,149,702	32.83	248,271	5.5
2017	539,683.06	83,421	65,572	0.0935	636,016	33.35	19,073	4.5
2018	11,744,935.60	1,432,717	1,126,165	0.0738	14,142,252	33.80	418,417	3.5
2019	499,285.70	44,291	34,814	0.0536	614,257	34.14	17,994	2.5
2020	8,527,709.20	465,244	365,698	0.0330	10,720,324	34.24	313,070	1.5
2021	24,979,214.43	475,069	373,420	0.0115	32,099,559	33.68	953,155	0.5
TOTAL	143,144,394.64	63,662,026	50,040,540		136,047,173		5,515,552	

COMPOSITE ANNUAL ACCRUAL RATE	3.85%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	16.36
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	25.87

Enbridge Gas Distribution

Account #: 454.00 - Underground Storage - Well Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1963	177,937.86	165,952	177,938	1.0000	0	4.23	0	58.5
1964	45,733.53	42,418	45,734	1.0000	0	4.49	0	57.5
1966	90,870.93	83,314	90,871	1.0000	0	5.03	0	55.5
1968	88,382.30	80,030	88,382	1.0000	0	5.58	0	53.5
1969	207,234.01	186,412	207,234	1.0000	0	5.86	0	52.5
1970	27,531.28	24,594	27,531	1.0000	0	6.15	0	51.5
1971	88,403.18	78,400	88,403	1.0000	0	6.44	0	50.5
1972	42,870.65	37,730	42,871	1.0000	0	6.74	0	49.5
1973	53,146.89	46,399	53,147	1.0000	0	7.05	0	48.5
1974	83,889.03	72,621	83,889	1.0000	0	7.37	0	47.5
1975	40,956.20	35,139	40,956	1.0000	0	7.70	0	46.5
1976	34,738.49	29,525	34,738	1.0000	0	8.03	0	45.5
1978	140,818.42	117,258	140,818	1.0000	0	8.74	0	43.5
1980	37,576.46	30,583	37,576	1.0000	0	9.49	0	41.5
1983	173,295.60	135,621	173,296	1.0000	0	10.70	0	38.5
1984	284,018.12	219,064	284,018	1.0000	0	11.12	0	37.5
1987	600,425.36	441,174	600,425	1.0000	0	12.45	0	34.5
1988	146,890.66	106,010	146,891	1.0000	0	12.92	0	33.5
1989	99,628.33	70,554	99,628	1.0000	0	13.39	0	32.5
1990	181,525.51	126,013	181,526	1.0000	0	13.88	0	31.5
1992	128,229.62	85,255	128,230	1.0000	0	14.87	0	29.5
1994	16,438.13	10,417	16,438	1.0000	0	15.90	0	27.5
1996	793,244.21	476,524	793,244	1.0000	0	16.95	0	25.5
1997	764,393.62	446,063	764,394	1.0000	0	17.48	0	24.5
1998	307,272.19	173,891	307,272	1.0000	0	18.03	0	23.5
1999	626,388.03	343,150	626,388	1.0000	0	18.57	0	22.5

Enbridge Gas Distribution

Account #: 454.00 - Underground Storage - Well Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2000	70,309.90	37,213	70,310	1.0000	0	19.12	0	21.5
2001	57,334.99	29,256	57,335	1.0000	0	19.68	0	20.5
2002	14,028.42	6,885	14,028	1.0000	0	20.23	0	19.5
2003	203,654.25	95,887	199,028	0.9773	4,626	20.79	222	18.5
2004	8,713.16	3,925	8,146	0.9349	567	21.35	27	17.5
2005	186,049.07	79,915	165,876	0.8916	20,173	21.91	921	16.5
2006	90,324.50	36,869	76,526	0.8472	13,799	22.47	614	15.5
2007	38,223.77	14,767	30,651	0.8019	7,572	23.03	329	14.5
2008	127,788.06	46,515	96,549	0.7555	31,239	23.59	1,324	13.5
2009	452,559.45	154,402	320,483	0.7082	132,077	24.14	5,472	12.5
2010	609,408.90	193,693	402,038	0.6597	207,371	24.68	8,402	11.5
2011	98,504.69	28,959	60,108	0.6102	38,397	25.22	1,523	10.5
2012	524,881.85	141,503	293,711	0.5596	231,171	25.74	8,982	9.5
2013	216,506.27	52,967	109,941	0.5078	106,565	26.24	4,061	8.5
2014	443,047.44	97,082	201,507	0.4548	241,541	26.73	9,037	7.5
2015	942,966.94	181,981	377,728	0.4006	565,239	27.18	20,795	6.5
2016	1,119,442.63	186,051	386,175	0.3450	733,268	27.59	26,575	5.5
2018	1,140,005.87	125,839	261,196	0.2291	878,809	28.21	31,155	3.5
2020	1,443,806.93	73,073	151,674	0.1051	1,292,133	28.14	45,922	1.5
2021	295,121.32	5,341	11,086	0.0376	284,035	27.13	10,470	0.5

Enbridge Gas Distribution

Account #: 454.00 - Underground Storage - Well Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	13,364,517.02	5,256,233	8,575,936		4,788,581		175,830	

COMPOSITE ANNUAL ACCRUAL RATE	1.32%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.64
COMPOSITE AVERAGE AGE (YEARS)	17.35
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	21.38

Enbridge Gas Distribution

Account #: 455.00 - Underground Storage - Field Lines

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -8%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1955	272,765.58	268,629	194,742	0.6611	99,844	6.43	15,538	66.5
1957	4,356.45	4,245	3,078	0.6541	1,627	6.98	233	64.5
1959	140,235.90	135,068	97,918	0.6465	53,537	7.58	7,061	62.5
1960	4,017.00	3,845	2,787	0.6424	1,551	7.90	196	61.5
1961	1,659,538.56	1,577,674	1,143,734	0.6381	648,568	8.23	78,801	60.5
1963	4,131,236.55	3,870,751	2,806,098	0.6289	1,655,637	8.93	185,365	58.5
1964	17,191.07	15,981	11,585	0.6240	6,981	9.30	750	57.5
1965	20,038.98	18,474	13,393	0.6188	8,250	9.69	851	56.5
1966	64,320.80	58,780	42,612	0.6134	26,854	10.09	2,661	55.5
1967	29,148.03	26,392	19,133	0.6078	12,347	10.51	1,175	54.5
1968	83,864.48	75,200	54,516	0.6019	36,058	10.94	3,297	53.5
1969	29,046.54	25,781	18,690	0.5958	12,681	11.38	1,114	52.5
1970	40,725.80	35,760	25,924	0.5894	18,059	11.84	1,525	51.5
1971	206,105.20	178,948	129,728	0.5828	92,866	12.32	7,540	50.5
1972	0.00	0	0	0.0000	0	12.81	0	49.5
1973	57,775.16	48,962	35,495	0.5689	26,902	13.31	2,021	48.5
1974	50,670.55	42,388	30,729	0.5615	23,995	13.82	1,736	47.5
1975	85,834.18	70,836	51,353	0.5540	41,348	14.35	2,881	46.5
1976	4,518,605.77	3,676,586	2,665,339	0.5462	2,214,756	14.89	148,700	45.5
1977	2,028,929.38	1,626,606	1,179,207	0.5381	1,012,037	15.45	65,516	44.5
1978	17,311.17	13,666	9,907	0.5299	8,789	16.01	549	43.5
1979	26,912.68	20,906	15,156	0.5214	13,910	16.59	839	42.5
1980	4,259.92	3,254	2,359	0.5127	2,242	17.18	131	41.5
1982	124,293.39	91,611	66,414	0.4947	67,823	18.38	3,690	39.5
1983	446,656.30	323,023	234,176	0.4854	248,213	18.99	13,068	38.5
1984	164,679.78	116,764	84,648	0.4759	93,206	19.62	4,751	37.5

Enbridge Gas Distribution

Account #: 455.00 - Underground Storage - Field Lines

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -8%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1985	761,952.26	529,241	383,673	0.4662	439,236	20.25	21,687	36.5
1986	22,979.98	15,623	11,326	0.4563	13,493	20.90	646	35.5
1987	6,330,534.25	4,208,720	3,051,108	0.4463	3,785,869	21.54	175,723	34.5
1988	1,232,367.16	800,463	580,295	0.4360	750,661	22.20	33,811	33.5
1989	205,491.17	130,273	94,441	0.4255	127,490	22.87	5,575	32.5
1990	597,014.44	369,017	267,519	0.4149	377,257	23.54	16,027	31.5
1991	4,306,848.74	2,592,658	1,879,545	0.4041	2,771,851	24.22	114,450	30.5
1992	32,053,202.42	18,770,422	13,607,604	0.3931	21,009,854	24.91	843,581	29.5
1993	489,237.92	278,356	201,794	0.3819	326,583	25.60	12,758	28.5
1994	1,444,423.00	797,402	578,076	0.3706	981,901	26.30	37,336	27.5
1995	20,739.05	11,093	8,042	0.3590	14,356	27.01	532	26.5
1996	3,574,761.51	1,849,809	1,341,018	0.3473	2,519,725	27.72	90,895	25.5
1997	8,871,581.69	4,433,955	3,214,393	0.3355	6,366,916	28.44	223,857	24.5
1998	1,316,983.06	634,624	460,070	0.3235	962,271	29.17	32,989	23.5
1999	7,563,883.83	3,507,516	2,542,771	0.3113	5,626,223	29.90	188,153	22.5
2000	1,318,514.97	587,157	425,659	0.2989	998,337	30.64	32,580	21.5
2001	5,290,704.84	2,257,420	1,636,515	0.2864	4,077,446	31.39	129,899	20.5
2002	6,565,346.39	2,677,395	1,940,975	0.2737	5,149,599	32.14	160,214	19.5
2003	2,377,916.74	924,327	670,090	0.2609	1,898,060	32.90	57,691	18.5
2004	2,770,988.88	1,023,601	742,059	0.2480	2,250,609	33.66	66,855	17.5
2005	818,209.01	286,267	207,529	0.2348	676,137	34.43	19,636	16.5
2006	2,199,942.90	726,252	526,496	0.2216	1,849,443	35.21	52,529	15.5
2007	679,282.81	210,695	152,743	0.2082	580,882	35.99	16,141	14.5
2008	7,248,883.16	2,102,353	1,524,099	0.1947	6,304,695	36.77	171,455	13.5
2009	969,493.90	261,456	189,542	0.1810	857,511	37.56	22,831	12.5
2010	1,258,563.41	313,575	227,326	0.1672	1,131,923	38.35	29,516	11.5

Enbridge Gas Distribution

Account #: 455.00 - Underground Storage - Field Lines

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life

Survivor Curve: R3

ASL: 55

Net Salvage: -8%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2011	21,687,579.09	4,954,257	3,591,585	0.1533	19,831,000	39.14	506,648	10.5
2012	2,903,018.46	602,497	436,780	0.1393	2,698,480	39.94	67,570	9.5
2013	6,911,335.55	1,288,775	934,297	0.1252	6,529,946	40.73	160,324	8.5
2014	1,734,537.51	286,605	207,774	0.1109	1,665,526	41.52	40,113	7.5
2015	10,643,064.83	1,530,776	1,109,735	0.0965	10,384,775	42.31	245,456	6.5
2016	4,852,743.44	593,279	430,098	0.0821	4,810,865	43.09	111,656	5.5
2017	4,394,903.55	441,745	320,243	0.0675	4,426,253	43.85	100,936	4.5
2018	6,619,007.16	520,240	377,148	0.0528	6,771,380	44.59	151,849	3.5
2019	3,046,093.03	172,098	124,762	0.0379	3,165,018	45.29	69,884	2.5
2020	9,513,160.76	325,186	235,743	0.0229	10,038,471	45.89	218,739	1.5
2021	15,096,270.33	174,528	126,524	0.0078	16,177,448	46.21	350,096	0.5
TOTAL	201,920,080.43	73,519,785	53,298,115		164,775,572		5,130,626	

COMPOSITE ANNUAL ACCRUAL RATE	2.54%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.26
COMPOSITE AVERAGE AGE (YEARS)	18.42
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	33.44

Enbridge Gas Distribution

Account #: 456.00 - Underground Storage - Compressor Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -6%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1964	3,122,735.26	3,264,001	3,114,015	0.9408	196,084	0.81	196,084	57.5
1969	39,587.01	40,515	38,653	0.9211	3,309	1.88	1,764	52.5
1971	1,966,168.04	1,991,155	1,899,658	0.9115	184,480	2.36	78,227	50.5
1973	3,059,499.98	3,062,678	2,921,943	0.9010	321,127	2.86	112,413	48.5
1975	3,560,744.10	3,518,870	3,357,173	0.8895	417,216	3.38	123,563	46.5
1976	869,820.08	853,526	814,305	0.8832	107,704	3.65	29,502	45.5
1980	534,002.97	505,897	482,650	0.8527	83,393	4.93	16,902	41.5
1981	3,857,456.42	3,613,891	3,447,828	0.8432	641,076	5.32	120,427	40.5
1982	21,553,977.99	19,944,776	19,028,284	0.8328	3,818,932	5.75	664,371	39.5
1983	35,604.20	32,498	31,005	0.8215	6,736	6.21	1,085	38.5
1984	36,826.21	33,110	31,588	0.8092	7,447	6.71	1,110	37.5
1985	3,035,927.13	2,684,835	2,561,462	0.7960	656,620	7.25	90,575	36.5
1986	174,742.13	151,793	144,818	0.7818	40,409	7.82	5,168	35.5
1987	191,540.75	163,223	155,722	0.7670	47,311	8.41	5,622	34.5
1988	13,449,779.13	11,230,193	10,714,149	0.7515	3,542,617	9.03	392,388	33.5
1989	1,154,800.08	943,713	900,348	0.7355	323,740	9.66	33,528	32.5
1990	20,655,614.53	16,501,337	15,743,077	0.7190	6,151,875	10.30	597,498	31.5
1991	3,067,806.17	2,392,764	2,282,813	0.7020	969,062	10.95	88,492	30.5
1992	33,864,526.11	25,751,705	24,568,377	0.6844	11,328,021	11.62	974,763	29.5
1993	2,473,866.11	1,831,382	1,747,227	0.6663	875,071	12.31	71,096	28.5
1994	1,776,507.78	1,278,257	1,219,519	0.6476	663,579	13.01	50,996	27.5
1995	10,667,839.78	7,447,912	7,105,670	0.6284	4,202,240	13.73	305,973	26.5
1996	45,381,028.25	30,686,547	29,276,455	0.6086	18,827,435	14.47	1,300,820	25.5
1997	11,640,151.43	7,608,569	7,258,944	0.5883	5,079,616	15.23	333,509	24.5
1998	1,391,664.48	877,501	837,178	0.5675	637,986	16.01	39,860	23.5
1999	4,654,045.40	2,824,533	2,694,741	0.5462	2,238,547	16.80	133,261	22.5

Enbridge Gas Distribution

Account #: 456.00 - Underground Storage - Compressor Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -6%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2000	4,988,117.04	2,906,839	2,773,265	0.5245	2,514,139	17.61	142,788	21.5
2001	1,393,425.54	777,719	741,982	0.5023	735,049	18.43	39,876	20.5
2002	2,321,925.56	1,237,770	1,180,893	0.4798	1,280,348	19.27	66,426	19.5
2003	3,794,425.49	1,926,128	1,837,619	0.4569	2,184,472	20.13	108,512	18.5
2004	2,422,471.54	1,167,133	1,113,501	0.4336	1,454,319	21.00	69,247	17.5
2005	2,936,058.69	1,337,773	1,276,300	0.4101	1,835,922	21.89	83,886	16.5
2006	43,213,036.23	18,546,140	17,693,918	0.3863	28,111,900	22.78	1,233,932	15.5
2007	2,368,670.11	953,291	909,486	0.3622	1,601,304	23.69	67,593	14.5
2008	5,267,235.41	1,977,872	1,886,986	0.3380	3,696,284	24.61	150,202	13.5
2009	8,230,265.74	2,866,994	2,735,251	0.3135	5,988,831	25.54	234,518	12.5
2010	18,963,278.98	6,087,488	5,807,759	0.2889	14,293,317	26.47	539,913	11.5
2011	22,734,383.87	6,673,226	6,366,581	0.2642	17,731,866	27.42	646,729	10.5
2012	742,894.91	197,548	188,471	0.2393	598,998	28.37	21,115	9.5
2013	3,838,998.78	914,428	872,409	0.2144	3,196,930	29.33	109,013	8.5
2014	8,802,463.82	1,851,868	1,766,772	0.1894	7,563,839	30.29	249,725	7.5
2015	15,532,044.54	2,834,446	2,704,200	0.1642	13,759,768	31.26	440,236	6.5
2016	71,203,157.99	11,003,454	10,497,829	0.1391	64,977,519	32.23	2,016,318	5.5
2017	189,165,293.56	23,934,821	22,834,982	0.1139	177,680,230	33.20	5,351,978	4.5
2018	13,369,323.73	1,316,565	1,256,067	0.0886	12,915,416	34.17	377,932	3.5
2019	4,246,796.96	298,917	285,181	0.0634	4,216,424	35.15	119,958	2.5
2020	12,480,935.91	527,470	503,232	0.0380	12,726,560	36.12	352,318	1.5
2021	52,097,290.66	734,665	700,906	0.0127	54,522,222	37.08	1,470,241	0.5

Enbridge Gas Distribution

Account #: 456.00 - Underground Storage - Compressor Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -6%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	682,328,756.58	239,307,734	228,311,196		494,957,286		19,661,453	

COMPOSITE ANNUAL ACCRUAL RATE	2.88%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	13.53
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	25.52

Enbridge Gas Distribution

Account #: 457.00 - Underground Storage - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: -14%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1963	130,385.00	147,379	148,639	1.0000	0	0.50	0	58.5
1967	523,963.56	584,940	597,318	1.0000	0	1.15	0	54.5
1971	29,834.21	32,656	34,011	1.0000	0	2.10	0	50.5
1973	1,199,914.00	1,298,884	1,367,902	1.0000	0	2.58	0	48.5
1975	332,093.69	355,248	378,587	1.0000	0	3.05	0	46.5
1978	2,395,075.78	2,511,667	2,730,386	1.0000	0	3.79	0	43.5
1979	10,902.48	11,348	12,429	1.0000	0	4.05	0	42.5
1984	99,162.31	98,379	108,055	0.9559	4,990	5.59	893	37.5
1987	944,986.41	900,624	989,204	0.9182	88,080	6.77	13,016	34.5
1988	1,869,447.09	1,753,904	1,926,408	0.9039	204,761	7.21	28,416	33.5
1989	980,804.54	904,684	993,664	0.8887	124,453	7.67	16,231	32.5
1990	3,532,968.44	3,199,615	3,514,311	0.8726	513,273	8.15	62,968	31.5
1991	7,023,272.22	6,236,333	6,849,704	0.8555	1,156,826	8.66	133,621	30.5
1992	3,495,881.74	3,039,126	3,338,038	0.8376	647,268	9.18	70,475	29.5
1993	2,347,659.40	1,995,138	2,191,369	0.8188	484,962	9.73	49,839	28.5
1994	446,474.29	370,336	406,760	0.7992	102,221	10.30	9,929	27.5
1995	605,066.61	489,043	537,142	0.7787	152,634	10.88	14,032	26.5
1996	401,253.74	315,467	346,495	0.7575	110,934	11.48	9,667	25.5
1997	2,735,779.61	2,088,397	2,293,800	0.7355	824,988	12.09	68,248	24.5
1999	3,202,846.25	2,291,190	2,516,539	0.6892	1,134,706	13.36	84,958	22.5
2000	10,904,216.06	7,526,609	8,266,885	0.6650	4,163,921	14.01	297,232	21.5
2001	4,193,144.09	2,785,988	3,060,002	0.6401	1,720,182	14.67	117,228	20.5
2002	1,073,800.54	684,951	752,319	0.6146	471,813	15.35	30,737	19.5
2003	595,307.24	363,520	399,274	0.5883	279,377	16.04	17,420	18.5
2005	871,579.18	482,969	530,471	0.5339	463,130	17.45	26,548	16.5
2006	1,664,981.27	873,913	959,866	0.5057	938,212	18.16	51,650	15.5

Enbridge Gas Distribution

Account #: 457.00 - Underground Storage - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: -14%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	142,651.85	70,610	77,555	0.4769	85,068	18.89	4,502	14.5
2008	196,488.02	91,261	100,237	0.4475	123,759	19.64	6,303	13.5
2009	1,520,178.69	658,742	723,532	0.4175	1,009,472	20.38	49,521	12.5
2010	1,655,695.06	664,942	730,342	0.3869	1,157,150	21.14	54,728	11.5
2011	992,690.96	366,616	402,674	0.3558	728,993	21.91	33,270	10.5
2012	6,657,164.95	2,239,907	2,460,212	0.3242	5,128,956	22.69	226,069	9.5
2013	596,503.55	180,795	198,576	0.2920	481,438	23.47	20,512	8.5
2014	845,386.68	227,588	249,972	0.2594	713,769	24.26	29,422	7.5
2015	270,244.87	63,467	69,710	0.2263	238,370	25.05	9,515	6.5
2016	3,130,628.26	626,213	687,804	0.1927	2,881,112	25.85	111,474	5.5
2017	2,697,412.08	444,421	488,132	0.1587	2,586,918	26.64	97,119	4.5
2018	598,240.75	77,204	84,798	0.1243	597,197	27.42	21,781	3.5
2019	1,993,546.54	185,206	203,422	0.0895	2,069,221	28.18	73,436	2.5
2020	331,510.40	18,658	20,494	0.0542	357,428	28.88	12,375	1.5
2021	3,954,990.47	75,375	82,789	0.0184	4,425,900	29.41	150,499	0.5
TOTAL	77,194,132.88	47,333,313	51,829,828		36,171,484		2,003,637	

COMPOSITE ANNUAL ACCRUAL RATE	2.60%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.67
COMPOSITE AVERAGE AGE (YEARS)	20.48
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	15.57

Enbridge Gas Inc.

Account #: 461.00 - Transmission Plant - Land Rights Intangible
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1993	11,038.40	5,419	11,038	1.0000	0	29.55	0	28.5
1994	19,068,363.22	9,054,437	10,314,762	0.5409	8,753,602	30.41	287,814	27.5
1995	307,429.86	140,986	140,986	0.4586	166,444	31.28	5,320	26.5
1996	1,391,196.94	615,200	615,200	0.4422	775,997	32.17	24,125	25.5
1997	62,046.97	26,413	26,413	0.4257	35,634	33.05	1,078	24.5
1998	503,792.08	206,078	206,078	0.4091	297,714	33.95	8,769	23.5
1999	711,691.20	279,196	279,196	0.3923	432,495	34.85	12,409	22.5
2000	258.49	97	97	0.3754	161	35.77	5	21.5
2001	1,176,471.38	421,755	421,755	0.3585	754,716	36.68	20,573	20.5
2002	2,381,758.03	813,253	813,253	0.3415	1,568,505	37.61	41,705	19.5
2003	163,275.68	52,956	52,956	0.3243	110,320	38.54	2,862	18.5
2004	30,153.80	9,262	9,262	0.3071	20,892	39.48	529	17.5
2005	10,475.96	3,037	3,037	0.2899	7,439	40.42	184	16.5
2006	6,134,786.52	1,672,172	1,672,172	0.2726	4,462,615	41.37	107,882	15.5
2007	2,323,578.49	592,989	592,989	0.2552	1,730,589	42.32	40,896	14.5
2008	42,768.12	10,170	10,170	0.2378	32,598	43.27	753	13.5
2009	3,804,899.79	838,357	838,357	0.2203	2,966,543	44.23	67,069	12.5
2010	71,413.93	14,486	14,486	0.2028	56,928	45.19	1,260	11.5
2011	164,175.01	30,424	30,424	0.1853	133,751	46.16	2,898	10.5
2012	1,305.80	219	219	0.1678	1,087	47.13	23	9.5
2013	1,415,439.30	212,573	212,573	0.1502	1,202,866	48.10	25,009	8.5
2014	795,695.18	105,491	105,491	0.1326	690,204	49.07	14,066	7.5
2015	1,820,400.00	209,262	209,262	0.1150	1,611,138	50.04	32,194	6.5
2016	36,012,160.06	3,504,404	3,504,404	0.0973	32,507,756	51.02	637,164	5.5
2017	3,519,784.25	280,362	280,362	0.0797	3,239,423	52.00	62,303	4.5
2018	187,496.57	11,621	11,621	0.0620	175,876	52.97	3,320	3.5

Enbridge Gas Inc.

Account #: 461.00 - Transmission Plant - Land Rights Intangible
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2019	4,288,988.25	189,969	189,969	0.0443	4,099,019	53.94	75,988	2.5
2020	976,025.97	25,953	25,953	0.0266	950,073	54.91	17,302	1.5
2021	794,532.50	7,049	7,049	0.0089	787,484	55.86	14,098	0.5
TOTAL	88,171,401.75	19,333,589	20,599,533		67,571,869		1,507,597	

COMPOSITE ANNUAL ACCRUAL RATE	1.71%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	12.57
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	44.35

Enbridge Gas Distribution

Account #: 462.00 - Transmission Plant - Compressor Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 50
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1971	1,187,168.14	1,106,385	1,187,168	0.9524	59,358	6.40	9,280	50.5
1973	391,089.80	358,264	391,090	0.9524	19,554	7.09	2,758	48.5
1988	282,072.74	201,514	282,073	0.9524	14,104	15.74	896	33.5
1989	12,325,933.56	8,573,393	10,766,415	0.8319	2,175,816	16.56	131,379	32.5
1991	14,715,774.88	9,658,970	9,658,970	0.6251	5,792,593	18.29	316,688	30.5
1994	110,397.09	65,657	65,657	0.5664	50,260	21.05	2,388	27.5
1995	629,437.89	361,086	361,086	0.5463	299,824	22.00	13,626	26.5
1997	227,989.35	121,067	121,067	0.5057	118,322	23.94	4,942	24.5
1998	160,773.04	81,919	81,919	0.4853	86,893	24.93	3,486	23.5
2000	120,574.86	56,230	56,230	0.4441	70,373	26.91	2,615	21.5
2001	24,159.27	10,744	10,744	0.4235	14,624	27.90	524	20.5
2002	20,357.96	8,612	8,612	0.4029	12,764	28.90	442	19.5
2004	197,385.39	74,940	74,940	0.3616	132,314	30.90	4,282	17.5
2005	19,215.94	6,879	6,879	0.3409	13,298	31.90	417	16.5
2006	31,818.59	10,700	10,700	0.3203	22,710	32.90	690	15.5
2007	5,084,372.73	1,599,464	1,599,464	0.2996	3,739,127	33.90	110,308	14.5
2008	2,175,036.86	637,044	637,044	0.2789	1,646,744	34.90	47,188	13.5
2009	1,004,663.82	272,458	272,458	0.2583	782,439	35.90	21,797	12.5
2010	310,888.09	77,566	77,566	0.2376	248,866	36.90	6,745	11.5
2011	604,639.05	137,738	137,738	0.2170	497,133	37.90	13,118	10.5
2012	410,069.29	84,518	84,518	0.1963	346,055	38.90	8,897	9.5
2013	811,486.43	149,648	149,648	0.1756	702,413	39.90	17,606	8.5
2014	20,001,022.91	3,254,490	3,254,490	0.1550	17,746,584	40.90	433,932	7.5
2015	33,713,841.29	4,754,349	4,754,349	0.1343	30,645,184	41.90	731,438	6.5
2016	23,302,948.09	2,780,629	2,780,629	0.1136	21,687,467	42.90	505,569	5.5
2017	34,622,648.10	3,380,199	3,380,199	0.0930	32,973,581	43.90	751,155	4.5

Enbridge Gas Distribution

Account #: 462.00 - Transmission Plant - Compressor Structures and Improvements
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 50
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2018	154,780.99	11,753	11,753	0.0723	150,767	44.90	3,358	3.5
2019	189,237.30	10,264	10,264	0.0517	188,435	45.90	4,106	2.5
2020	268,143.29	8,726	8,726	0.0310	272,824	46.90	5,818	1.5
2021	10,254,031.19	111,233	111,233	0.0103	10,655,500	47.90	222,466	0.5
TOTAL	163,351,957.93	37,966,441	40,353,631		131,165,925		3,377,911	

COMPOSITE ANNUAL ACCRUAL RATE 2.07%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.25

COMPOSITE AVERAGE AGE (YEARS) 10.84

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 37.72

Enbridge Gas Distribution

Account #: 463.00 - Transmission Plant - Measuring and Regulating Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 55
Net Salvage: -6%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1931	583.35	610	618	1.0000	0	1.19	0	90.5
1954	826.60	826	876	1.0000	0	4.09	0	67.5
1958	322,414.22	317,307	341,759	1.0000	0	4.89	0	63.5
1959	3,884.40	3,806	4,117	1.0000	0	5.12	0	62.5
1960	170,882.37	166,621	181,135	1.0000	0	5.36	0	61.5
1961	68,923.58	66,863	73,059	1.0000	0	5.61	0	60.5
1962	19,415.52	18,733	20,580	1.0000	0	5.87	0	59.5
1963	5,480.23	5,257	5,809	1.0000	0	6.14	0	58.5
1964	82,870.60	79,009	87,843	1.0000	0	6.43	0	57.5
1965	113,466.20	107,467	120,274	1.0000	0	6.73	0	56.5
1966	12,889.72	12,123	13,663	1.0000	0	7.05	0	55.5
1968	16,260.15	15,056	17,236	1.0000	0	7.75	0	53.5
1969	11,439.49	10,501	12,126	1.0000	0	8.12	0	52.5
1970	3,366.51	3,062	3,569	1.0000	0	8.52	0	51.5
1971	12,064.50	10,866	12,788	1.0000	0	8.93	0	50.5
1972	4,526.37	4,034	4,798	1.0000	0	9.37	0	49.5
1973	7,696.36	6,782	8,067	0.9888	91	9.84	9	48.5
1974	96,065.03	83,641	99,483	0.9770	2,345	10.33	227	47.5
1975	55,403.35	47,621	56,641	0.9645	2,087	10.85	192	46.5
1976	12,794.87	10,848	12,902	0.9513	660	11.39	58	45.5
1977	88,859.03	74,239	88,300	0.9375	5,890	11.96	493	44.5
1978	80,811.59	66,468	79,058	0.9229	6,603	12.56	526	43.5
1979	99,637.42	80,599	95,865	0.9077	9,751	13.19	739	42.5
1981	238,599.34	186,095	221,342	0.8752	31,573	14.54	2,171	40.5
1982	146,799.48	112,240	133,499	0.8579	22,108	15.26	1,449	39.5
1983	45,243.40	33,872	40,288	0.8401	7,670	16.01	479	38.5

Enbridge Gas Distribution

Account #: 463.00 - Transmission Plant - Measuring and Regulating Structures and Improvements
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 55
Net Salvage: -6%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1984	229,535.79	168,061	199,893	0.8216	43,415	16.79	2,586	37.5
1985	23,764.54	16,996	20,216	0.8025	4,975	17.60	283	36.5
1986	627,855.34	438,100	521,079	0.7830	144,447	18.43	7,838	35.5
1987	841,421.49	572,104	680,464	0.7629	211,443	19.29	10,964	34.5
1988	22,839.52	15,113	17,975	0.7425	6,234	20.16	309	33.5
1989	791,278.65	508,905	605,295	0.7217	233,460	21.07	11,083	32.5
1990	785,719.08	490,519	583,426	0.7005	249,436	21.98	11,346	31.5
1991	996,030.58	602,803	716,978	0.6791	338,815	22.92	14,783	30.5
1992	337,836.22	197,945	235,437	0.6574	122,670	23.87	5,139	29.5
1993	713,832.36	404,366	480,956	0.6356	275,706	24.83	11,104	28.5
1994	97,420.36	53,279	63,370	0.6137	39,895	25.80	1,546	27.5
1995	926,577.87	488,509	581,035	0.5916	401,137	26.78	14,979	26.5
1997	47,478.23	23,153	27,539	0.5472	22,788	28.75	793	24.5
1998	104,058.13	48,680	57,901	0.5249	52,401	29.75	1,762	23.5
1999	5,385.29	2,412	2,869	0.5026	2,839	30.74	92	22.5
2000	49,451.57	21,168	25,178	0.4803	27,241	31.74	858	21.5
2002	289,511.03	112,406	133,697	0.4357	173,185	33.74	5,133	19.5
2005	125,526.90	41,240	49,051	0.3686	84,007	36.74	2,287	16.5
2006	162,810.09	50,247	59,764	0.3463	112,814	37.74	2,990	15.5
2007	272,875.71	78,783	93,705	0.3240	195,543	38.74	5,048	14.5
2008	432,488.79	116,254	138,273	0.3016	320,165	39.74	8,057	13.5
2009	8,146.72	2,028	2,412	0.2793	6,224	40.74	153	12.5
2010	20,858.65	4,776	5,681	0.2569	16,429	41.74	394	11.5
2011	84,169.67	17,597	20,930	0.2346	68,290	42.74	1,598	10.5
2012	203,670.58	38,526	45,823	0.2122	170,068	43.74	3,888	9.5
2013	3,000.00	508	604	0.1899	2,576	44.74	58	8.5

Enbridge Gas Distribution

Account #: 463.00 - Transmission Plant - Measuring and Regulating Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 55
Net Salvage: -6%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2014	16,610.27	2,480	2,950	0.1676	14,657	45.74	320	7.5
2016	210,132.56	23,012	27,371	0.1229	195,370	47.74	4,093	5.5
2017	54,330.04	4,868	5,790	0.1005	51,800	48.74	1,063	4.5
2018	48,913.00	3,409	4,054	0.0782	47,793	49.74	961	3.5
2019	212,068.09	10,556	12,556	0.0559	212,236	50.74	4,183	2.5
2021	785,483.10	7,820	9,301	0.0112	823,311	52.74	15,612	0.5
TOTAL	11,252,283.90	6,091,172	7,167,268		4,760,153		157,645	

COMPOSITE ANNUAL ACCRUAL RATE	1.40%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.64
COMPOSITE AVERAGE AGE (YEARS)	28.34
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	26.24

Enbridge Gas Distribution

Account #: 464.00 - Transmission Plant - Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 50
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1931	698.96	734	693	0.9444	41	0.00	41	90.5
1948	681.35	697	658	0.9198	57	1.96	29	73.5
1950	589.52	601	567	0.9162	52	2.20	24	71.5
1952	892.48	905	855	0.9122	82	2.45	34	69.5
1953	5,232.50	5,294	5,000	0.9100	494	2.58	191	68.5
1954	817.91	825	780	0.9077	79	2.72	29	67.5
1955	104.89	106	100	0.9053	10	2.87	4	66.5
1960	6,978.68	6,913	6,528	0.8909	799	3.69	217	61.5
1961	49,895.81	49,234	46,495	0.8875	5,895	3.88	1,520	60.5
1962	8,662.20	8,512	8,039	0.8838	1,057	4.08	259	59.5
1963	6,687.24	6,543	6,179	0.8800	843	4.28	197	58.5
1967	16,358.53	15,674	14,802	0.8618	2,375	5.23	454	54.5
1969	1,290.60	1,221	1,153	0.8507	202	5.78	35	52.5
1970	1,257.77	1,181	1,116	0.8447	205	6.08	34	51.5
1975	5,102.82	4,582	4,327	0.8077	1,031	7.87	131	46.5
1981	7,801.40	6,461	6,102	0.7449	2,090	10.85	193	40.5
1987	55,785.33	40,873	38,599	0.6590	19,975	14.94	1,337	34.5
1988	17,757.05	12,686	11,980	0.6425	6,665	15.74	424	33.5
1989	17,076.29	11,878	11,217	0.6256	6,713	16.56	405	32.5
1991	29,342.88	19,260	18,188	0.5903	12,622	18.29	690	30.5
1992	45,070.75	28,672	27,077	0.5722	20,248	19.19	1,055	29.5
1994	14,615.78	8,693	8,209	0.5349	7,138	21.05	339	27.5
1995	76,532.46	43,904	41,462	0.5160	38,897	22.00	1,768	26.5
1996	123,181.55	68,047	64,262	0.4968	65,079	22.97	2,833	25.5
2014	9,027.77	1,469	1,387	0.1463	8,092	40.90	198	7.5
2016	1,316,312.85	157,069	148,333	0.1073	1,233,796	42.90	28,762	5.5

Enbridge Gas Distribution

Account #: 464.00 - Transmission Plant - Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 50
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	2,606.59	254	240	0.0878	2,497	43.90	57	4.5
2019	927,988.75	50,333	47,533	0.0488	926,855	45.90	20,194	2.5
2021	171,866.85	1,864	1,761	0.0098	178,700	47.90	3,731	0.5
TOTAL	2,920,217.56	554,483	523,642		2,542,587		65,183	

COMPOSITE ANNUAL ACCRUAL RATE	2.23%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.18
COMPOSITE AVERAGE AGE (YEARS)	9.30
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	39.70

Enbridge Gas Distribution

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1900	504.57	565	565	1.0000	0	0.00	0	121.5
1910	13,248.18	14,838	14,838	1.0000	0	0.00	0	111.5
1921	33,733.67	37,782	37,782	1.0000	0	0.00	0	100.5
1926	7,918.72	8,869	8,869	1.0000	0	0.00	0	95.5
1927	69,978.99	78,376	78,376	1.0000	0	0.00	0	94.5
1928	40,173.58	44,994	44,994	1.0000	0	0.00	0	93.5
1930	61,570.86	68,585	68,959	1.0000	0	0.50	0	91.5
1931	156,074.83	173,819	174,804	1.0000	0	0.51	0	90.5
1935	124.68	138	140	1.0000	0	1.10	0	86.5
1936	751,729.53	829,475	841,937	1.0000	0	1.28	0	85.5
1937	408,311.87	449,361	457,309	1.0000	0	1.49	0	84.5
1938	150,740.66	165,453	168,830	1.0000	0	1.70	0	83.5
1939	139,371.43	152,551	156,096	1.0000	0	1.92	0	82.5
1940	166,120.78	181,285	186,055	1.0000	0	2.14	0	81.5
1941	259,663.51	282,495	290,823	1.0000	0	2.37	0	80.5
1942	231,275.70	250,812	259,029	1.0000	0	2.60	0	79.5
1943	63,399.04	68,523	71,007	1.0000	0	2.85	0	78.5
1945	67,400.64	72,341	75,489	1.0000	0	3.33	0	76.5
1946	307,753.16	329,089	344,684	1.0000	0	3.58	0	75.5
1947	639,932.51	681,713	716,724	1.0000	0	3.83	0	74.5
1948	1,858.42	1,972	2,081	1.0000	0	4.08	0	73.5
1950	49,994.63	52,617	55,994	1.0000	0	4.59	0	71.5
1951	1,184,149.93	1,240,898	1,326,248	1.0000	0	4.85	0	70.5
1952	11,672.21	12,176	13,073	1.0000	0	5.12	0	69.5
1953	1,068,946.00	1,109,847	1,197,220	1.0000	0	5.39	0	68.5
1954	167,992.60	173,557	188,152	1.0000	0	5.68	0	67.5

Enbridge Gas Distribution

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1955	670,889.45	689,482	751,396	1.0000	0	5.97	0	66.5
1956	121,386.63	124,060	135,953	1.0000	0	6.28	0	65.5
1957	17,289,437.66	17,566,237	19,364,170	1.0000	0	6.60	0	64.5
1958	19,410,275.93	19,597,297	21,739,509	1.0000	0	6.94	0	63.5
1959	3,170,065.01	3,179,169	3,550,473	1.0000	0	7.30	0	62.5
1960	973,648.73	969,442	1,090,487	1.0000	0	7.68	0	61.5
1961	842,536.00	832,460	943,640	1.0000	0	8.08	0	60.5
1962	2,095,941.04	2,053,854	2,347,454	1.0000	0	8.51	0	59.5
1963	907,327.59	881,279	1,015,651	0.9995	556	8.96	62	58.5
1964	10,668,880.18	10,265,265	11,830,454	0.9901	118,692	9.43	12,584	57.5
1965	5,558,167.09	5,294,307	6,101,553	0.9801	123,595	9.93	12,442	56.5
1966	6,082,507.70	5,732,012	6,605,997	0.9697	206,412	10.46	19,732	55.5
1967	9,103,641.70	8,482,491	9,775,853	0.9588	420,225	11.01	38,168	54.5
1968	3,358,225.53	3,091,949	3,563,391	0.9474	197,821	11.58	17,083	53.5
1969	1,939,472.95	1,763,456	2,032,337	0.9356	139,872	12.17	11,494	52.5
1970	6,615,568.92	5,937,125	6,842,384	0.9235	567,053	12.77	44,401	51.5
1971	9,268,739.44	8,205,951	9,457,147	0.9110	923,841	13.39	69,019	50.5
1972	12,962,889.20	11,315,900	13,041,284	0.8983	1,477,152	14.01	105,442	49.5
1973	2,587,292.63	2,225,862	2,565,249	0.8852	332,519	14.64	22,712	48.5
1974	4,701,695.38	3,984,175	4,591,660	0.8720	674,239	15.28	44,123	47.5
1975	26,894,698.08	22,435,438	25,856,266	0.8584	4,265,796	15.93	267,760	46.5
1976	4,453,962.91	3,655,507	4,212,878	0.8445	775,561	16.59	46,746	45.5
1977	1,105,639.75	892,223	1,028,264	0.8304	210,053	17.26	12,169	44.5
1978	3,650,138.28	2,894,278	3,335,581	0.8159	752,574	17.94	41,941	43.5
1979	11,045,642.38	8,600,076	9,911,367	0.8012	2,459,753	18.64	131,991	42.5
1980	2,363,387.55	1,805,557	2,080,859	0.7861	566,136	19.34	29,273	41.5

Enbridge Gas Distribution

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1981	19,253,434.14	14,421,833	16,620,792	0.7708	4,943,054	20.06	246,456	40.5
1982	31,736,353.72	23,290,132	26,841,279	0.7551	8,703,437	20.78	418,762	39.5
1983	585,609.64	420,694	484,839	0.7392	171,044	21.52	7,947	38.5
1984	18,409,411.00	12,935,017	14,907,275	0.7230	5,711,265	22.28	256,394	37.5
1985	40,319,036.48	27,683,765	31,904,828	0.7065	13,252,493	23.04	575,239	36.5
1986	10,355,630.60	6,941,772	8,000,214	0.6898	3,598,092	23.81	151,095	35.5
1987	6,381,187.02	4,172,027	4,808,154	0.6728	2,338,776	24.60	95,070	34.5
1988	33,840,488.10	21,557,417	24,844,369	0.6555	13,056,977	25.40	514,089	33.5
1989	64,565,346.35	40,031,813	46,135,636	0.6380	26,177,552	26.21	998,847	32.5
1990	35,227,934.04	21,234,762	24,472,517	0.6203	14,982,769	27.03	554,330	31.5
1991	33,945,460.29	19,869,585	22,899,186	0.6023	15,119,730	27.86	542,716	30.5
1992	69,166,629.12	39,265,037	45,251,946	0.5841	32,214,679	28.70	1,122,423	29.5
1993	35,102,013.98	19,300,548	22,243,386	0.5658	17,070,870	29.55	577,634	28.5
1994	34,556,578.01	18,377,939	21,180,102	0.5472	17,523,265	30.41	576,155	27.5
1995	30,037,510.10	15,428,117	17,780,509	0.5285	15,861,503	31.28	507,001	26.5
1996	51,558,774.26	25,535,712	29,429,252	0.5096	28,316,575	32.17	880,352	25.5
1997	19,704,937.40	9,394,863	10,827,338	0.4906	11,242,192	33.05	340,125	24.5
1998	34,226,277.63	15,680,438	18,071,302	0.4714	20,262,129	33.95	596,829	23.5
1999	53,916,470.45	23,689,549	27,301,597	0.4521	33,084,850	34.85	949,236	22.5
2000	17,677,659.48	7,433,409	8,566,813	0.4327	11,232,166	35.77	314,050	21.5
2001	46,466,250.25	18,656,685	21,501,350	0.4132	30,540,850	36.68	832,537	20.5
2002	51,922,238.74	19,856,345	22,883,927	0.3935	35,268,980	37.61	937,773	19.5
2003	7,521,099.34	2,732,062	3,148,631	0.3738	5,275,000	38.54	136,870	18.5
2004	4,659,850.83	1,602,985	1,847,399	0.3540	3,371,634	39.48	85,408	17.5
2005	11,997,470.67	3,895,239	4,489,163	0.3341	8,948,004	40.42	221,381	16.5
2006	125,125,575.60	38,198,433	44,022,712	0.3141	96,117,932	41.37	2,323,615	15.5

Enbridge Gas Distribution

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	80,961,603.56	23,141,245	26,669,691	0.2941	64,007,305	42.32	1,512,567	14.5
2008	11,216,023.81	2,987,117	3,442,576	0.2740	9,119,371	43.27	210,743	13.5
2009	45,004,705.67	11,106,099	12,799,493	0.2539	37,605,777	44.23	850,203	12.5
2010	8,923,405.41	2,027,259	2,336,364	0.2338	7,657,850	45.19	169,444	11.5
2011	15,874,783.26	3,294,893	3,797,280	0.2136	13,982,477	46.16	302,916	10.5
2012	41,321,828.47	7,764,129	8,947,959	0.1933	37,332,489	47.13	792,157	9.5
2013	69,144,443.21	11,630,340	13,403,668	0.1731	64,038,108	48.10	1,331,406	8.5
2014	41,414,560.89	6,149,526	7,087,171	0.1528	39,297,138	49.07	800,829	7.5
2015	156,789,681.68	20,186,423	23,264,334	0.1325	152,340,109	50.04	3,044,100	6.5
2016	671,012,315.57	73,133,014	84,283,919	0.1121	667,249,874	51.02	13,078,350	5.5
2017	200,758,114.35	17,909,919	20,640,721	0.0918	204,208,367	52.00	3,927,461	4.5
2018	15,795,859.13	1,096,508	1,263,698	0.0714	16,427,665	52.97	310,132	3.5
2019	99,159,853.46	4,919,068	5,669,100	0.0510	105,389,936	53.94	1,953,723	2.5
2020	73,822,444.83	2,198,539	2,533,759	0.0306	80,147,379	54.91	1,459,588	1.5
2021	189,897,248.28	1,886,865	2,174,563	0.0102	210,510,355	55.86	3,768,579	0.5
TOTAL	2,783,251,797.20	799,994,108	919,330,147		2,197,911,866		49,201,672	

COMPOSITE ANNUAL ACCRUAL RATE	1.77%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	15.26
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	42.33

Enbridge Gas Distribution

Account #: 466.00 - Transmission Plant - Compressor Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 30
Net Salvage: -7%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1970	5,225,157.68	5,590,919	5,512,645	0.9860	78,274	0.00	78,274	51.5
1972	6,694,440.19	7,163,051	7,062,767	0.9860	100,284	0.00	100,284	49.5
1988	3,767,639.42	3,707,591	3,655,684	0.9068	375,690	2.93	128,417	33.5
1990	29,064,577.31	27,933,720	27,542,643	0.8856	3,556,454	3.57	996,345	31.5
1993	4,270,487.16	3,905,489	3,850,812	0.8427	718,610	4.84	148,320	28.5
1994	6,598,676.71	5,906,971	5,824,273	0.8249	1,236,311	5.37	230,197	27.5
1995	11,074,974.21	9,680,461	9,544,933	0.8055	2,305,290	5.94	388,118	26.5
1996	41,359,020.59	35,220,151	34,727,064	0.7847	9,527,088	6.54	1,456,569	25.5
2001	2,237,627.66	1,617,269	1,594,627	0.6660	799,635	9.85	81,190	20.5
2004	1,108,053.64	700,901	691,088	0.5829	494,529	12.10	40,862	17.5
2006	6,339,908.87	3,598,418	3,548,040	0.5230	3,235,662	13.72	235,828	15.5
2007	81,039,112.91	43,263,771	42,658,072	0.4920	44,053,779	14.56	3,025,304	14.5
2008	80,181,083.22	40,045,329	39,484,689	0.4602	46,309,070	15.42	3,002,673	13.5
2009	1,978,036.78	918,540	905,680	0.4279	1,210,820	16.30	74,272	12.5
2010	5,756,021.34	2,467,972	2,433,420	0.3951	3,725,523	17.20	216,615	11.5
2011	17,185,515.58	6,748,675	6,654,193	0.3619	11,734,309	18.11	647,948	10.5
2012	33,368,237.21	11,886,734	11,720,318	0.3283	23,983,695	19.04	1,259,978	9.5
2013	1,949,552.75	622,768	614,049	0.2944	1,471,972	19.97	73,703	8.5
2014	6,525,504.74	1,842,743	1,816,944	0.2602	5,165,346	20.92	246,932	7.5
2015	203,461,376.38	49,873,123	49,174,892	0.2259	168,528,780	21.87	7,704,710	6.5
2016	153,100,505.79	31,797,098	31,351,934	0.1914	132,465,607	22.84	5,800,785	5.5
2017	235,646,157.74	40,087,906	39,526,669	0.1568	212,614,720	23.80	8,932,001	4.5
2018	2,388,189.10	316,302	311,873	0.1220	2,243,489	24.78	90,551	3.5
2019	620,131.22	58,718	57,896	0.0873	605,644	25.75	23,519	2.5
2020	1,757,876.43	99,958	98,558	0.0524	1,782,369	26.73	66,691	1.5
2021	62,362,174.13	1,183,386	1,166,818	0.0175	65,560,708	27.69	2,367,370	0.5

Enbridge Gas Distribution

Account #: 466.00 - Transmission Plant - Compressor Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 30
Net Salvage: -7%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	1,005,060,038.76	336,237,963	331,530,582		743,883,660		37,417,455	

COMPOSITE ANNUAL ACCRUAL RATE	3.72%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	9.59
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	19.61

Enbridge Gas Distribution

Account #: 467.00 - Transmission Plant - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1959	188,441.62	216,708	209,505	0.9668	7,203	0.00	7,203	62.5
1966	9,026.68	10,161	9,823	0.9463	558	1.20	464	55.5
1968	11,759.11	13,120	12,684	0.9380	839	1.64	511	53.5
1970	18,456.51	20,388	19,710	0.9286	1,515	2.11	716	51.5
1971	7,194.17	7,904	7,641	0.9236	632	2.36	268	50.5
1972	11,696.49	12,778	12,354	0.9184	1,097	2.61	421	49.5
1973	8,407.17	9,130	8,827	0.9130	841	2.86	294	48.5
1974	1,862.82	2,010	1,944	0.9073	199	3.11	64	47.5
1975	59,355.58	63,638	61,523	0.9013	6,736	3.38	1,995	46.5
1976	31,572.65	33,612	32,494	0.8950	3,814	3.65	1,045	45.5
1977	376,455.39	397,718	384,498	0.8881	48,426	3.94	12,294	44.5
1978	178,048.72	186,546	180,346	0.8808	24,410	4.25	5,749	43.5
1979	927,242.77	962,672	930,673	0.8728	135,656	4.58	29,643	42.5
1980	479,947.53	493,292	476,895	0.8640	75,044	4.93	15,210	41.5
1981	294,824.68	299,661	289,700	0.8545	49,348	5.32	9,270	40.5
1982	440,527.13	442,248	427,548	0.8439	79,058	5.75	13,754	39.5
1983	549,778.12	544,420	526,323	0.8325	105,922	6.21	17,054	38.5
1984	524,308.07	511,420	494,420	0.8200	108,534	6.71	16,171	37.5
1985	152,873.85	146,673	141,798	0.8066	34,007	7.25	4,691	36.5
1986	747,775.12	704,719	681,295	0.7923	178,647	7.82	22,847	35.5
1987	1,032,489.94	954,547	922,818	0.7772	264,545	8.41	31,439	34.5
1988	542,274.92	491,229	474,900	0.7615	148,716	9.03	16,472	33.5
1989	1,145,802.99	1,015,863	982,096	0.7453	335,578	9.66	34,754	32.5
1990	3,690,685.77	3,198,748	3,092,423	0.7286	1,151,866	10.30	111,874	31.5
1991	4,736,358.91	4,007,823	3,874,604	0.7114	1,572,209	10.95	143,569	30.5
1992	4,637,724.55	3,826,114	3,698,935	0.6935	1,634,448	11.62	140,642	29.5

Enbridge Gas Distribution

Account #: 467.00 - Transmission Plant - Measuring and Regulating Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1993	4,885,103.21	3,923,453	3,793,038	0.6752	1,824,830	12.31	148,261	28.5
1994	20,380,731.29	15,909,731	15,380,896	0.6562	8,056,945	13.01	619,177	27.5
1995	27,519,668.78	20,844,584	20,151,716	0.6368	11,495,903	13.73	837,037	26.5
1996	9,287,945.53	6,813,736	6,587,250	0.6167	4,093,888	14.47	282,854	25.5
1997	3,029,524.31	2,148,378	2,076,967	0.5962	1,406,986	15.23	92,378	24.5
1998	1,600,719.85	1,095,015	1,058,617	0.5751	782,211	16.01	48,870	23.5
1999	1,407,652.27	926,837	896,029	0.5535	722,771	16.80	43,027	22.5
2000	3,391,667.93	2,144,320	2,073,043	0.5315	1,827,375	17.61	103,784	21.5
2001	312,821.79	189,421	183,125	0.5090	176,620	18.43	9,582	20.5
2002	3,206,373.95	1,854,376	1,792,738	0.4862	1,894,593	19.27	98,294	19.5
2003	1,350,524.87	743,761	719,039	0.4630	834,065	20.13	41,431	18.5
2004	416,252.54	217,576	210,344	0.4394	268,347	21.00	12,777	17.5
2005	5,596,399.00	2,766,420	2,674,465	0.4156	3,761,393	21.89	171,863	16.5
2006	3,535,621.39	1,646,253	1,591,532	0.3914	2,474,433	22.78	108,612	15.5
2007	4,980,458.12	2,174,615	2,102,331	0.3671	3,625,196	23.69	153,025	14.5
2008	6,195,518.94	2,523,975	2,440,079	0.3425	4,684,768	24.61	190,370	13.5
2009	6,608,911.49	2,497,668	2,414,647	0.3177	5,185,602	25.54	203,065	12.5
2010	4,445,096.77	1,548,096	1,496,638	0.2928	3,615,224	26.47	136,561	11.5
2011	7,466,619.58	2,377,763	2,298,727	0.2677	6,287,885	27.42	229,336	10.5
2012	7,756,083.19	2,237,589	2,163,212	0.2425	6,756,284	28.37	238,157	9.5
2013	5,873,761.25	1,517,889	1,467,435	0.2172	5,287,391	29.33	180,296	8.5
2014	24,750,303.78	5,649,088	5,461,314	0.1919	23,001,535	30.29	759,411	7.5
2015	29,969,409.90	5,933,484	5,736,257	0.1664	28,728,564	31.26	919,154	6.5
2016	32,234,134.41	5,404,279	5,224,642	0.1409	31,844,612	32.23	988,170	5.5
2017	50,655,952.22	6,953,624	6,722,487	0.1154	51,531,858	33.20	1,552,212	4.5
2018	13,659,429.31	1,459,343	1,410,835	0.0898	14,297,509	34.17	418,375	3.5

Enbridge Gas Distribution

Account #: 467.00 - Transmission Plant - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2019	26,497,560.27	2,023,424	1,956,166	0.0642	28,516,028	35.15	811,283	2.5
2020	25,594,737.74	1,173,528	1,134,521	0.0385	28,299,428	36.12	783,432	1.5
2021	42,232,666.74	646,123	624,646	0.0129	47,942,921	37.08	1,292,824	0.5
TOTAL	395,646,541.68	123,917,493	119,798,512		335,195,011		12,112,033	

COMPOSITE ANNUAL ACCRUAL RATE	3.06%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.30
COMPOSITE AVERAGE AGE (YEARS)	10.81
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	27.66

Enbridge Gas Distribution

Account #: 471.00 - Distribution - Land Rights

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1982	734,045.10	480,972	445,483	0.6069	288,563	20.78	13,884	39.5
1983	73,108.81	46,893	43,433	0.5941	29,676	21.52	1,379	38.5
1984	173,766.21	109,012	100,968	0.5811	72,798	22.28	3,268	37.5
1985	3,426,337.47	2,100,521	1,945,531	0.5678	1,480,806	23.04	64,276	36.5
1986	958,048.88	573,408	531,098	0.5544	426,951	23.81	17,929	35.5
1987	354,429.13	206,898	191,632	0.5407	162,797	24.60	6,618	34.5
1988	100,679.11	57,264	53,039	0.5268	47,640	25.40	1,876	33.5
1989	57,560.44	31,865	29,514	0.5127	28,047	26.21	1,070	32.5
1990	233,617.04	125,732	116,455	0.4985	117,162	27.03	4,335	31.5
1991	115,800.71	60,520	56,055	0.4841	59,746	27.86	2,145	30.5
1992	108,308.90	54,898	50,847	0.4695	57,462	28.70	2,002	29.5
1993	151,770.02	74,508	69,011	0.4547	82,759	29.55	2,800	28.5
1994	3,464,454.84	1,645,065	1,523,681	0.4398	1,940,774	30.41	63,812	27.5
1995	498,278.96	228,509	211,648	0.4248	286,631	31.28	9,162	26.5
1996	331,266.13	146,489	135,680	0.4096	195,586	32.17	6,081	25.5
1997	389,245.74	165,700	153,473	0.3943	235,773	33.05	7,133	24.5
1998	491,767.35	201,159	186,316	0.3789	305,451	33.95	8,997	23.5
1999	286,264.03	112,301	104,015	0.3634	182,249	34.85	5,229	22.5
2000	164,849.29	61,892	57,325	0.3477	107,524	35.77	3,006	21.5
2001	125,436.04	44,968	41,650	0.3320	83,786	36.68	2,284	20.5
2002	183,136.39	62,532	57,918	0.3163	125,218	37.61	3,329	19.5
2003	122,559.25	39,750	36,817	0.3004	85,742	38.54	2,225	18.5
2004	85,791.29	26,350	24,406	0.2845	61,385	39.48	1,555	17.5
2005	196,577.85	56,985	52,780	0.2685	143,798	40.42	3,558	16.5
2006	203,679.93	55,517	51,421	0.2525	152,259	41.37	3,681	15.5
2007	233,697.12	59,641	55,240	0.2364	178,457	42.32	4,217	14.5

Enbridge Gas Distribution

Account #: 471.00 - Distribution - Land Rights

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life

Survivor Curve: R4

ASL: 60

Net Salvage: 0%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2008	7,953,167.56	1,891,191	1,751,646	0.2202	6,201,521	43.27	143,313	13.5
2009	499,300.58	110,014	101,896	0.2041	397,404	44.23	8,985	12.5
2010	230,269.02	46,709	43,262	0.1879	187,007	45.19	4,138	11.5
2011	252,988.91	46,883	43,424	0.1716	209,565	46.16	4,540	10.5
2012	399,570.90	67,033	62,087	0.1554	337,484	47.13	7,161	9.5
2013	541,565.43	81,333	75,332	0.1391	466,234	48.10	9,693	8.5
2014	4,486,011.49	594,745	550,861	0.1228	3,935,151	49.07	80,194	7.5
2015	476,115.17	54,731	50,693	0.1065	425,422	50.04	8,501	6.5
2016	33,197,490.81	3,230,504	2,992,136	0.0901	30,205,355	51.02	592,036	5.5
2017	354,078.01	28,203	26,122	0.0738	327,956	52.00	6,307	4.5
2018	499,779.33	30,976	28,691	0.0574	471,089	52.97	8,894	3.5
2019	611,812.17	27,099	25,099	0.0410	586,713	53.94	10,877	2.5
2020	826,239.39	21,970	20,349	0.0246	805,890	54.91	14,676	1.5
2021	314,694.85	2,792	2,586	0.0082	312,109	55.86	5,587	0.5
TOTAL	63,907,559.65	13,063,533	12,099,619		51,807,941		1,150,752	

COMPOSITE ANNUAL ACCRUAL RATE	1.80%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.19
COMPOSITE AVERAGE AGE (YEARS)	11.80
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	45.17

Enbridge Gas Distribution

Account #: 472.00 - Distribution - Structures - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1928	39,923.45	39,923	35,490	0.8890	4,433	0.00	4,433	93.5
1929	1,751.32	1,751	1,557	0.8890	194	0.00	194	92.5
1930	6,119.60	6,120	5,440	0.8890	680	0.00	680	91.5
1937	96.35	96	86	0.8889	11	0.00	11	84.5
1939	4,831.67	4,832	4,295	0.8890	537	0.00	537	82.5
1940	1,334.00	1,334	1,186	0.8890	148	0.00	148	81.5
1941	244.99	245	218	0.8890	27	0.00	27	80.5
1947	211.52	206	183	0.8664	28	1.94	15	74.5
1948	502.38	487	433	0.8624	69	2.27	31	73.5
1949	340.83	329	293	0.8583	48	2.59	19	72.5
1952	6,519.54	6,203	5,514	0.8458	1,005	3.55	283	69.5
1953	1,030.38	975	867	0.8415	163	3.86	42	68.5
1954	244,600.76	230,347	204,769	0.8372	39,832	4.18	9,537	67.5
1956	248,675.48	231,694	205,966	0.8283	42,710	4.80	8,897	65.5
1957	26,308.73	24,377	21,670	0.8237	4,639	5.11	908	64.5
1958	481,214.00	443,365	394,133	0.8190	87,081	5.42	16,064	63.5
1959	1,017,508.01	932,060	828,560	0.8143	188,948	5.73	32,976	62.5
1960	1,029,622.81	937,568	833,457	0.8095	196,166	6.04	32,487	61.5
1961	367,420.70	332,537	295,611	0.8046	71,810	6.35	11,315	60.5
1962	885,238.46	796,189	707,778	0.7995	177,461	6.65	26,667	59.5
1963	68,372.27	61,100	54,315	0.7944	14,057	6.96	2,019	58.5
1964	487,356.37	432,648	384,606	0.7892	102,751	7.27	14,132	57.5
1965	92,352.29	81,429	72,387	0.7838	19,965	7.58	2,634	56.5
1966	111,478.42	97,607	86,768	0.7783	24,710	7.89	3,133	55.5
1967	113,272.42	98,464	87,530	0.7727	25,742	8.20	3,141	54.5
1968	7,137,865.37	6,158,700	5,474,816	0.7670	1,663,049	8.51	195,517	53.5

Enbridge Gas Distribution

Account #: 472.00 - Distribution - Structures - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1969	1,425,993.59	1,220,967	1,085,387	0.7611	340,607	8.82	38,636	52.5
1970	43,915.34	37,304	33,162	0.7551	10,753	9.13	1,178	51.5
1971	427,607.50	360,276	320,270	0.7490	107,338	9.44	11,373	50.5
1972	205,086.10	171,338	152,312	0.7427	52,774	9.75	5,413	49.5
1973	139,443.32	115,482	102,659	0.7362	36,785	10.06	3,655	48.5
1974	15,224,527.59	12,494,815	11,107,346	0.7296	4,117,182	10.38	396,752	47.5
1975	34,356.61	27,933	24,832	0.7228	9,525	10.69	891	46.5
1976	118,650.93	95,536	84,927	0.7158	33,724	11.01	3,063	45.5
1977	973,962.60	776,362	690,152	0.7086	283,811	11.33	25,058	44.5
1978	4,746.86	3,744	3,329	0.7012	1,418	11.65	122	43.5
1979	43,220.27	33,725	29,980	0.6937	13,240	11.97	1,107	42.5
1980	975,054.36	752,317	668,777	0.6859	306,278	12.29	24,927	41.5
1981	1,478,165.14	1,127,201	1,002,032	0.6779	476,133	12.61	37,758	40.5
1982	2,062,178.80	1,553,472	1,380,969	0.6697	681,210	12.93	52,665	39.5
1983	915,606.25	681,027	605,403	0.6612	310,203	13.26	23,392	38.5
1984	257,314.51	188,870	167,897	0.6525	89,417	13.59	6,580	37.5
1985	1,375,714.09	995,914	885,324	0.6435	490,390	13.92	35,230	36.5
1986	318,773.12	227,459	202,201	0.6343	116,572	14.25	8,180	35.5
1987	720,426.42	506,355	450,127	0.6248	270,299	14.59	18,532	34.5
1988	721,418.62	499,106	443,683	0.6150	277,735	14.92	18,613	33.5
1989	1,319,056.66	897,602	797,929	0.6049	521,127	15.26	34,150	32.5
1990	527,425.71	352,735	313,566	0.5945	213,860	15.60	13,709	31.5
1991	1,793,157.64	1,177,598	1,046,833	0.5838	746,325	15.94	46,812	30.5
1992	633,017.80	407,834	362,546	0.5727	270,472	16.29	16,605	29.5
1993	706,848.03	446,321	396,760	0.5613	310,088	16.64	18,640	28.5
1994	3,260,358.72	2,015,445	1,791,642	0.5495	1,468,716	16.99	86,464	27.5

Enbridge Gas Distribution

Account #: 472.00 - Distribution - Structures - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1995	11,944,393.09	7,220,136	6,418,386	0.5374	5,526,007	17.34	318,697	26.5
1996	1,350,706.55	797,381	708,837	0.5248	641,870	17.70	36,274	25.5
1997	8,462,798.23	4,872,385	4,331,337	0.5118	4,131,461	18.05	228,841	24.5
1998	911,442.78	511,003	454,259	0.4984	457,183	18.42	24,826	23.5
1999	767,871.44	418,534	372,059	0.4845	395,813	18.78	21,076	22.5
2000	451,349.63	238,734	212,224	0.4702	239,125	19.15	12,488	21.5
2001	203,608.45	104,300	92,718	0.4554	110,890	19.52	5,681	20.5
2002	4,289,775.17	2,123,487	1,887,688	0.4400	2,402,088	19.89	120,750	19.5
2003	2,025,648.86	966,569	859,237	0.4242	1,166,412	20.27	57,542	18.5
2004	1,615,369.24	740,962	658,683	0.4078	956,686	20.65	46,325	17.5
2005	508,719.57	223,621	198,789	0.3908	309,931	21.04	14,733	16.5
2006	4,177,657.04	1,753,691	1,558,955	0.3732	2,618,702	21.42	122,231	15.5
2007	3,657,733.59	1,460,445	1,298,272	0.3549	2,359,462	21.82	108,154	14.5
2008	1,237,359.39	467,768	415,826	0.3361	821,534	22.21	36,988	13.5
2009	2,031,196.60	723,172	642,868	0.3165	1,388,328	22.61	61,406	12.5
2010	5,588,477.85	1,862,241	1,655,451	0.2962	3,933,027	23.01	170,921	11.5
2011	1,371,242.88	424,526	377,385	0.2752	993,858	23.42	42,444	10.5
2012	7,773,909.77	2,216,246	1,970,146	0.2534	5,803,764	23.82	243,619	9.5
2013	1,879,077.30	487,956	433,771	0.2308	1,445,306	24.23	59,643	8.5
2014	3,856,005.55	899,703	799,797	0.2074	3,056,209	24.64	124,014	7.5
2015	5,161,274.07	1,063,149	945,093	0.1831	4,216,181	25.06	168,273	6.5
2016	7,875,429.65	1,398,795	1,243,468	0.1579	6,631,962	25.47	260,426	5.5
2017	4,032,417.18	597,452	531,109	0.1317	3,501,309	25.87	135,331	4.5
2018	1,788,351.24	210,253	186,905	0.1045	1,601,446	26.27	60,961	3.5
2019	5,744,929.53	492,676	437,967	0.0762	5,306,962	26.65	199,123	2.5
2020	3,896,100.71	205,052	182,283	0.0468	3,713,818	27.00	137,545	1.5

Enbridge Gas Distribution

Account #: 472.00 - Distribution - Structures - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2021	80,149,541.03	1,442,974	1,282,741	0.0160	78,866,800	27.27	2,891,823	0.5
TOTAL	220,832,605.09	72,010,537	64,014,227		156,818,378		7,005,483	

COMPOSITE ANNUAL ACCRUAL RATE	3.17%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	15.68
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	21.69

Enbridge Gas Inc.

Account #: 472.31 - Distribution - Structures - Stoney Creek

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2046

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1992	1,114,233.02	745,014	401,617	0.3604	712,616	14.62	48,743	29.5
1996	264,569.14	164,748	88,811	0.3357	175,758	15.45	11,376	25.5
2010	11,256.60	4,367	2,354	0.2091	8,902	18.14	491	11.5
2011	3,046.29	1,110	598	0.1964	2,448	18.32	134	10.5
2012	24,238.48	8,223	4,433	0.1829	19,806	18.50	1,070	9.5
2013	26,834,440.69	8,391,142	4,523,435	0.1686	22,311,006	18.68	1,194,215	8.5
2014	72,795.00	20,713	11,166	0.1534	61,629	18.86	3,268	7.5
2015	15,084.11	3,840	2,070	0.1372	13,014	19.03	684	6.5
2016	3,000.00	668	360	0.1200	2,640	19.20	137	5.5
2018	3,400.00	517	279	0.0819	3,121	19.53	160	3.5
2019	76,764.68	8,655	4,666	0.0608	72,099	19.67	3,665	2.5
2021	1,239,286.80	30,390	16,383	0.0132	1,222,904	19.89	61,485	0.5
TOTAL	29,662,114.81	9,379,387	5,056,171		24,605,944		1,325,428	

COMPOSITE ANNUAL ACCRUAL RATE	4.47%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.17
COMPOSITE AVERAGE AGE (YEARS)	9.09
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	18.55

Enbridge Gas Inc.

Account #: 472.32 - Distribution - Structures - Win-Rhodes

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2046

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1961	180,426.39	163,296	94,729	0.5250	85,698	6.35	13,503	60.5
2007	129,381.63	58,466	33,916	0.2621	95,465	17.59	5,428	14.5
2008	12,068.02	5,209	3,022	0.2504	9,046	17.77	509	13.5
2009	22,631,922.21	9,288,069	5,388,051	0.2381	17,243,871	17.96	960,216	12.5
2011	65,635.22	23,910	13,870	0.2113	51,765	18.32	2,825	10.5
2013	8,062.10	2,521	1,462	0.1814	6,600	18.68	353	8.5
2015	4,463.00	1,136	659	0.1477	3,804	19.03	200	6.5
2017	65,272.23	12,307	7,139	0.1094	58,133	19.37	3,002	4.5
2018	27,450.03	4,173	2,421	0.0882	25,029	19.53	1,282	3.5
2019	65,992.08	7,441	4,316	0.0654	61,676	19.67	3,135	2.5
2021	25,873.03	634	368	0.0142	25,505	19.89	1,282	0.5
TOTAL	23,216,545.94	9,567,162	5,549,955		17,666,591		991,735	

COMPOSITE ANNUAL ACCRUAL RATE 4.27%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.24

COMPOSITE AVERAGE AGE (YEARS) 12.80

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 17.88

Enbridge Gas Inc.

Account #: 472.33 - Distribution - Structures - London Admin
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2026

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1955	199.68	191	136	0.6808	64	3.18	20	66.5
1959	5,165.84	4,896	3,492	0.6761	1,673	3.45	485	62.5
1960	1,011,560.18	957,077	682,748	0.6749	328,812	3.50	93,920	61.5
1969	386,858.53	360,578	257,225	0.6649	129,633	3.83	33,879	52.5
1970	878,076.95	816,968	582,799	0.6637	295,278	3.85	76,652	51.5
1971	5,845,067.46	5,428,354	3,872,415	0.6625	1,972,653	3.88	508,850	50.5
1975	3,368.30	3,104	2,214	0.6573	1,154	3.96	291	46.5
1980	452,780.36	412,505	294,268	0.6499	158,512	4.05	39,121	41.5
1982	2,909.02	2,637	1,881	0.6465	1,028	4.08	252	39.5
1995	16,817.65	14,496	10,341	0.6149	6,477	4.24	1,526	26.5
1997	18,229.57	15,527	11,076	0.6076	7,153	4.26	1,677	24.5
2004	318,242.92	255,112	181,989	0.5719	136,254	4.33	31,463	17.5
2006	592,897.90	463,013	330,299	0.5571	262,599	4.35	60,394	15.5
2007	1,524,698.50	1,172,436	836,378	0.5486	688,320	4.36	157,995	14.5
2008	75,814.20	57,290	40,869	0.5391	34,945	4.36	8,006	13.5
2009	87,714.83	64,981	46,355	0.5285	41,360	4.37	9,458	12.5
2010	76,186.98	55,169	39,356	0.5166	36,831	4.38	8,407	11.5
2011	3,270,478.37	2,306,368	1,645,289	0.5031	1,625,189	4.39	370,268	10.5
2012	32,272.28	22,061	15,738	0.4877	16,534	4.40	3,760	9.5
2013	84,576.51	55,709	39,741	0.4699	44,836	4.40	10,179	8.5
2014	1,057,271.39	665,667	474,866	0.4491	582,406	4.41	132,000	7.5
2015	8,913.65	5,306	3,785	0.4246	5,129	4.42	1,160	6.5
2016	5,711.46	3,165	2,257	0.3953	3,454	4.43	780	5.5
2017	64,922.75	32,703	23,329	0.3593	41,594	4.43	9,382	4.5
2018	113,400.71	49,987	35,659	0.3144	77,742	4.44	17,509	3.5
2019	86,366.66	31,083	22,173	0.2567	64,193	4.45	14,437	2.5

Enbridge Gas Inc.

Account #: 472.33 - Distribution - Structures - London Admin
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2026

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2020	473,100.18	119,223	85,050	0.1798	388,050	4.45	87,157	1.5
2021	3,296,299.21	332,491	237,188	0.0720	3,059,111	4.46	686,365	0.5
TOTAL	19,789,902.04	13,708,094	9,778,917		10,010,985		2,365,393	

COMPOSITE ANNUAL ACCRUAL RATE	11.95%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.49
COMPOSITE AVERAGE AGE (YEARS)	26.77
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	4.16

Enbridge Gas Inc.

Account #: 472.34 - Distribution - Structures - Kingston Office
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2046

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2008	173.14	75	45	0.2574	129	17.77	7	13.5
2009	15,807,650.76	6,487,409	3,868,483	0.2447	11,939,168	17.96	664,826	12.5
2010	816,665.68	316,839	188,933	0.2313	627,733	18.14	34,602	11.5
2011	13,036.61	4,749	2,832	0.2172	10,205	18.32	557	10.5
2012	17,010.23	5,770	3,441	0.2023	13,569	18.50	733	9.5
2015	5,663.00	1,442	860	0.1518	4,803	19.03	252	6.5
2016	11,740.47	2,614	1,559	0.1328	10,182	19.20	530	5.5
2017	7,351.98	1,386	827	0.1124	6,525	19.37	337	4.5
2018	12,352.19	1,878	1,120	0.0906	11,233	19.53	575	3.5
2020	26,851.89	1,891	1,128	0.0420	25,724	19.80	1,299	1.5
2021	19,080.00	468	279	0.0146	18,801	19.89	945	0.5
TOTAL	16,737,575.95	6,824,521	4,069,504		12,668,072		704,665	

COMPOSITE ANNUAL ACCRUAL RATE	4.21%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.24
COMPOSITE AVERAGE AGE (YEARS)	12.40
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	17.98

Enbridge Gas Inc.

Account #: 472.35 - Distribution - Structures - Mainway

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2023

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2008	15,525,798.74	13,983,827	3,882,332	0.2501	11,643,466	1.49	7,821,646	13.5
2011	4,400.98	3,854	1,070	0.2431	3,331	1.49	2,234	10.5
2012	36,549.22	31,589	8,770	0.2399	27,779	1.49	18,621	9.5
2014	3,924.00	3,272	909	0.2315	3,015	1.49	2,019	7.5
2015	2,872.00	2,335	648	0.2257	2,224	1.49	1,488	6.5
2016	13,798.50	10,850	3,012	0.2183	10,786	1.49	7,216	5.5
2017	28,858.18	21,660	6,013	0.2084	22,845	1.50	15,276	4.5
2018	13,142.00	9,206	2,556	0.1945	10,586	1.50	7,075	3.5
2019	292,494.03	182,954	50,793	0.1737	241,701	1.50	161,475	2.5
2020	15,458.98	7,736	2,148	0.1389	13,311	1.50	8,889	1.5
TOTAL	15,937,296.63	14,257,283	3,958,252		11,979,045		8,045,940	

COMPOSITE ANNUAL ACCRUAL RATE	50.48%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.25
COMPOSITE AVERAGE AGE (YEARS)	13.24
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	1.49

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -32%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1900	2,525,390.77	3,333,516	2,908,182	0.8724	425,333	0.00	425,333	121.5
1901	28,468.71	37,579	32,784	0.8724	4,795	0.00	4,795	120.5
1909	61.08	81	70	0.8724	10	0.00	10	112.5
1911	1,994.22	2,632	2,297	0.8724	336	0.00	336	110.5
1912	5,372.22	7,091	6,187	0.8724	905	0.00	905	109.5
1913	1,997.63	2,637	2,300	0.8724	336	0.00	336	108.5
1914	1,947.23	2,570	2,242	0.8724	328	0.00	328	107.5
1915	398.55	526	459	0.8724	67	0.00	67	106.5
1916	492.24	650	567	0.8724	83	0.00	83	105.5
1917	248.91	329	287	0.8724	42	0.00	42	104.5
1918	433.13	572	499	0.8724	73	0.00	73	103.5
1919	361.62	477	416	0.8724	61	0.00	61	102.5
1920	933.30	1,232	1,075	0.8724	157	0.00	157	101.5
1921	549.45	725	633	0.8724	93	0.00	93	100.5
1922	312.68	413	360	0.8724	53	0.00	53	99.5
1923	382.19	504	440	0.8724	64	0.00	64	98.5
1924	509.56	673	587	0.8724	86	0.00	86	97.5
1925	7.63	10	9	0.8728	1	0.00	1	96.5
1926	93.15	123	107	0.8724	16	0.00	16	95.5
1927	147.94	195	170	0.8724	25	0.00	25	94.5
1928	37,036.47	48,888	42,650	0.8724	6,238	0.00	6,238	93.5
1929	270.46	357	311	0.8724	46	0.00	46	92.5
1930	1,367.06	1,805	1,574	0.8724	230	0.00	230	91.5
1931	597.08	788	688	0.8724	101	0.00	101	90.5
1932	799.42	1,049	915	0.8676	140	0.50	140	89.5
1933	67.19	88	77	0.8669	12	0.55	12	88.5

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -32%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1934	293.99	385	336	0.8649	52	0.76	52	87.5
1935	1,448.26	1,890	1,649	0.8625	263	1.00	263	86.5
1936	582.70	758	661	0.8599	108	1.24	87	85.5
1937	1,939.37	2,516	2,195	0.8573	365	1.49	245	84.5
1938	18,335.41	23,706	20,681	0.8545	3,522	1.75	2,011	83.5
1939	2,238.77	2,885	2,517	0.8516	439	2.01	218	82.5
1940	686.07	881	769	0.8487	137	2.28	60	81.5
1941	961.16	1,230	1,073	0.8457	196	2.54	77	80.5
1942	1,598.89	2,038	1,778	0.8426	332	2.81	118	79.5
1943	474.52	603	526	0.8395	101	3.08	33	78.5
1944	64.14	81	71	0.8362	14	3.35	4	77.5
1945	1,706.25	2,150	1,876	0.8330	376	3.62	104	76.5
1946	895.82	1,125	981	0.8296	201	3.89	52	75.5
1947	332.71	416	363	0.8262	76	4.16	18	74.5
1948	790.72	984	859	0.8227	185	4.44	42	73.5
1949	218.37	271	236	0.8191	52	4.72	11	72.5
1950	10,122.61	12,490	10,896	0.8155	2,466	4.99	494	71.5
1951	2,523.21	3,099	2,704	0.8117	627	5.27	119	70.5
1952	3,423.94	4,185	3,651	0.8079	868	5.55	156	69.5
1953	6,722.68	8,178	7,134	0.8039	1,740	5.83	298	68.5
1954	1,360,971.16	1,647,233	1,437,057	0.7999	359,425	6.12	58,769	67.5
1955	393,966.77	474,388	413,859	0.7958	106,177	6.40	16,593	66.5
1956	790,277.04	946,570	825,795	0.7916	217,371	6.68	32,521	65.5
1957	1,572,724.59	1,873,512	1,634,465	0.7873	441,532	6.97	63,338	64.5
1958	2,958,567.30	3,504,640	3,057,473	0.7829	847,836	7.26	116,788	63.5
1959	2,923,507.31	3,443,132	3,003,812	0.7784	855,218	7.55	113,283	62.5

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -32%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1960	4,203,017.94	4,920,660	4,292,818	0.7738	1,255,166	7.84	160,088	61.5
1961	5,504,304.17	6,404,651	5,587,462	0.7690	1,678,219	8.13	206,334	60.5
1962	6,938,872.93	8,022,842	6,999,183	0.7642	2,160,129	8.43	256,291	59.5
1963	5,952,667.63	6,837,686	5,965,245	0.7592	1,892,276	8.73	216,874	58.5
1964	4,395,501.85	5,015,074	4,375,186	0.7541	1,426,877	9.02	158,135	57.5
1965	4,401,757.23	4,987,346	4,350,995	0.7488	1,459,324	9.32	156,526	56.5
1966	4,454,596.24	5,011,012	4,371,641	0.7435	1,508,426	9.63	156,714	55.5
1967	5,278,397.26	5,893,693	5,141,699	0.7380	1,825,785	9.93	183,874	54.5
1968	6,156,073.38	6,821,020	5,950,705	0.7323	2,175,312	10.24	212,524	53.5
1969	8,793,794.32	9,666,466	8,433,092	0.7265	3,174,716	10.54	301,100	52.5
1970	5,945,925.49	6,482,393	5,655,285	0.7205	2,193,337	10.85	202,074	51.5
1971	7,056,155.79	7,627,483	6,654,269	0.7144	2,659,857	11.17	238,191	50.5
1972	9,494,932.00	10,173,460	8,875,398	0.7081	3,657,912	11.48	318,576	49.5
1973	8,745,454.00	9,285,049	8,100,342	0.7017	3,443,658	11.80	291,847	48.5
1974	8,520,993.43	8,961,258	7,817,864	0.6951	3,429,847	12.12	283,001	47.5
1975	8,236,428.38	8,577,067	7,482,693	0.6882	3,389,392	12.44	272,409	46.5
1976	7,871,902.71	8,114,033	7,078,739	0.6812	3,312,173	12.77	259,417	45.5
1977	8,474,464.88	8,642,780	7,540,022	0.6740	3,646,272	13.10	278,425	44.5
1978	8,925,236.51	9,002,478	7,853,824	0.6666	3,927,488	13.43	292,499	43.5
1979	9,516,026.91	9,488,677	8,277,988	0.6590	4,283,168	13.76	311,238	42.5
1980	10,728,819.66	10,570,732	9,221,981	0.6512	4,940,061	14.10	350,378	41.5
1981	5,905,160.29	5,746,077	5,012,918	0.6431	2,781,894	14.44	192,651	40.5
1982	2,977,540.18	2,859,909	2,495,005	0.6348	1,435,348	14.78	97,084	39.5
1983	2,644,927.33	2,506,219	2,186,443	0.6263	1,304,861	15.13	86,228	38.5
1984	3,045,016.05	2,844,763	2,481,791	0.6174	1,537,630	15.48	99,301	37.5
1985	2,389,466.91	2,199,544	1,918,898	0.6084	1,235,199	15.84	77,979	36.5

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -32%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1986	2,634,539.55	2,387,896	2,083,217	0.5990	1,394,375	16.20	86,072	35.5
1987	2,666,190.71	2,377,741	2,074,357	0.5894	1,445,014	16.56	87,235	34.5
1988	2,808,146.33	2,462,180	2,148,023	0.5795	1,558,730	16.93	92,050	33.5
1989	3,167,397.47	2,728,160	2,380,066	0.5693	1,800,899	17.31	104,056	32.5
1990	3,272,597.28	2,766,572	2,413,576	0.5587	1,906,252	17.69	107,788	31.5
1991	3,047,962.77	2,526,507	2,204,142	0.5478	1,819,169	18.07	100,677	30.5
1992	4,160,255.29	3,377,898	2,946,902	0.5366	2,544,635	18.46	137,854	29.5
1993	5,388,113.83	4,280,542	3,734,375	0.5251	3,377,935	18.85	179,163	28.5
1994	6,039,362.88	4,688,887	4,090,618	0.5131	3,881,341	19.25	201,576	27.5
1995	8,156,115.41	6,180,339	5,391,771	0.5008	5,374,302	19.66	273,325	26.5
1996	7,278,287.86	5,375,187	4,689,351	0.4881	4,917,989	20.08	244,951	25.5
1997	3,064,373.85	2,202,308	1,921,309	0.4750	2,123,665	20.50	103,598	24.5
1998	5,010,668.70	3,498,486	3,052,104	0.4615	3,561,979	20.93	170,201	23.5
1999	5,036,046.49	3,409,813	2,974,745	0.4475	3,672,837	21.36	171,911	22.5
2000	4,397,851.29	2,881,740	2,514,050	0.4331	3,291,114	21.81	150,892	21.5
2001	5,640,785.37	3,569,187	3,113,784	0.4182	4,332,053	22.27	194,560	20.5
2002	5,933,206.55	3,616,392	3,154,966	0.4028	4,676,867	22.73	205,756	19.5
2003	5,299,077.25	3,102,890	2,706,983	0.3870	4,287,799	23.20	184,786	18.5
2004	4,568,376.31	2,562,044	2,235,145	0.3707	3,795,112	23.69	160,202	17.5
2005	10,063,946.09	5,387,279	4,699,900	0.3538	8,584,509	24.19	354,921	16.5
2006	10,856,512.94	5,525,940	4,820,868	0.3364	9,509,729	24.70	385,062	15.5
2007	10,025,595.87	4,831,176	4,214,751	0.3185	9,019,035	25.22	357,627	14.5
2008	7,960,617.67	3,613,725	3,152,638	0.3000	7,355,377	25.76	285,586	13.5
2009	3,805,622.42	1,617,998	1,411,552	0.2810	3,611,869	26.31	137,287	12.5
2010	8,078,925.95	3,195,478	2,787,758	0.2614	7,876,425	26.88	293,037	11.5
2011	6,530,861.42	2,384,190	2,079,984	0.2413	6,540,753	27.47	238,142	10.5

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -32%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2012	12,311,181.31	4,108,964	3,584,688	0.2206	12,666,071	28.07	451,199	9.5
2013	14,888,036.99	4,490,363	3,917,424	0.1993	15,734,785	28.70	548,241	8.5
2014	14,420,870.07	3,873,921	3,379,636	0.1775	15,655,913	29.35	533,362	7.5
2015	13,410,628.90	3,149,739	2,747,854	0.1552	14,954,176	30.03	497,958	6.5
2016	10,157,808.29	2,035,123	1,775,456	0.1324	11,632,851	30.74	378,471	5.5
2017	11,386,910.26	1,880,263	1,640,355	0.1091	13,390,367	31.47	425,459	4.5
2018	10,343,154.30	1,336,734	1,166,176	0.0854	12,486,788	32.25	387,213	3.5
2019	13,688,543.27	1,270,237	1,108,163	0.0613	16,960,714	33.06	512,997	2.5
2020	12,701,976.85	710,029	619,434	0.0369	16,147,175	33.92	476,024	1.5
2021	112,224,699.54	2,096,391	1,828,906	0.0123	146,307,697	34.83	4,200,462	0.5
TOTAL	549,648,294.42	307,569,546	268,325,815		457,209,934		19,924,837	

COMPOSITE ANNUAL ACCRUAL RATE	3.63%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.49
COMPOSITE AVERAGE AGE (YEARS)	23.36
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	23.01

Enbridge Gas Distribution

Account #: 473.02 - Distribution - Services - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S3
ASL: 55
Net Salvage: -26%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1900	149,768.59	188,708	150,903	0.7997	37,805	0.00	37,805	121.5
1928	1,524.06	1,879	1,502	0.7823	418	2.08	201	93.5
1958	1,524.06	1,717	1,373	0.7148	548	7.54	73	63.5
1959	2,727.43	3,055	2,443	0.7110	993	7.80	127	62.5
1961	2,116.75	2,344	1,875	0.7028	793	8.34	95	60.5
1964	47,351.00	51,428	41,125	0.6893	18,537	9.21	2,013	57.5
1965	148,347.17	159,974	127,925	0.6844	58,992	9.52	6,199	56.5
1966	156,323.18	167,318	133,798	0.6793	63,170	9.83	6,423	55.5
1967	197,396.80	209,625	167,629	0.6740	81,091	10.16	7,978	54.5
1968	815,958.94	859,370	687,206	0.6684	340,903	10.50	32,452	53.5
1969	4,064.16	4,243	3,393	0.6626	1,728	10.86	159	52.5
1970	1,563,798.64	1,617,894	1,293,768	0.6566	676,618	11.22	60,303	51.5
1971	2,450,510.49	2,511,031	2,007,975	0.6503	1,079,668	11.60	93,104	50.5
1972	96,143.32	97,527	77,988	0.6438	43,152	11.99	3,600	49.5
1973	4,916,051.66	4,933,943	3,945,486	0.6370	2,248,739	12.39	181,520	48.5
1974	4,021,050.36	3,990,673	3,191,189	0.6299	1,875,334	12.81	146,447	47.5
1975	6,120,880.56	6,003,323	4,800,628	0.6225	2,911,681	13.24	219,960	46.5
1976	6,814,251.96	6,600,769	5,278,384	0.6148	3,307,574	13.68	241,708	45.5
1977	8,258,215.90	7,895,383	6,313,637	0.6068	4,091,715	14.15	289,235	44.5
1978	10,475,227.61	9,877,594	7,898,736	0.5984	5,300,051	14.63	362,366	43.5
1979	17,737,329.70	16,483,481	13,181,212	0.5898	9,167,824	15.12	606,202	42.5
1980	22,226,662.80	20,340,796	16,265,759	0.5808	11,739,836	15.64	750,725	41.5
1981	30,598,391.49	27,552,849	22,032,963	0.5715	16,521,010	16.17	1,021,671	40.5
1982	28,850,610.66	25,539,872	20,423,262	0.5618	15,928,507	16.72	952,565	39.5
1983	32,788,041.96	28,508,603	22,797,243	0.5518	18,515,690	17.29	1,070,775	38.5
1984	45,051,817.04	38,435,648	30,735,523	0.5414	26,029,766	17.88	1,455,524	37.5

Enbridge Gas Distribution

Account #: 473.02 - Distribution - Services - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S3
ASL: 55
Net Salvage: -26%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1985	44,178,902.73	36,945,005	29,543,513	0.5307	26,121,905	18.49	1,412,382	36.5
1986	45,656,546.02	37,384,963	29,895,330	0.5197	27,631,918	19.13	1,444,677	35.5
1987	48,183,301.68	38,588,105	30,857,437	0.5083	29,853,523	19.78	1,509,346	34.5
1988	52,722,048.58	41,247,411	32,983,983	0.4965	33,445,799	20.45	1,635,298	33.5
1989	53,099,568.05	40,531,537	32,411,525	0.4844	34,493,930	21.15	1,631,089	32.5
1990	61,581,712.67	45,800,981	36,625,299	0.4720	40,967,659	21.87	1,873,647	31.5
1991	68,045,080.48	49,242,869	39,377,646	0.4593	46,359,156	22.60	2,050,966	30.5
1992	86,254,726.77	60,649,198	48,498,853	0.4462	60,182,103	23.36	2,575,977	29.5
1993	100,416,338.86	68,498,546	54,775,677	0.4329	71,748,910	24.14	2,971,864	28.5
1994	114,613,463.09	75,727,180	60,556,140	0.4193	83,856,824	24.94	3,361,945	27.5
1995	144,689,462.64	92,436,986	73,918,335	0.4055	108,390,388	25.76	4,206,952	26.5
1996	122,662,528.22	75,638,333	60,485,092	0.3914	94,069,693	26.61	3,535,769	25.5
1997	111,013,734.49	65,949,487	52,737,292	0.3770	87,140,014	27.46	3,172,890	24.5
1998	106,872,602.30	61,043,501	48,814,161	0.3625	85,845,318	28.34	3,029,117	23.5
1999	112,351,680.12	61,569,904	49,235,106	0.3478	92,328,011	29.23	3,158,394	22.5
2000	128,015,893.22	67,154,960	53,701,262	0.3329	107,598,763	30.14	3,569,845	21.5
2001	115,289,893.04	57,752,316	46,182,326	0.3179	99,082,939	31.06	3,189,643	20.5
2002	96,249,612.37	45,919,863	36,720,365	0.3028	84,554,147	32.00	2,642,353	19.5
2003	115,205,243.80	52,198,486	41,741,140	0.2876	103,417,468	32.95	3,138,943	18.5
2004	69,353,793.26	29,749,781	23,789,766	0.2722	63,596,014	33.90	1,875,780	17.5
2005	97,395,107.31	39,416,975	31,520,253	0.2569	91,197,582	34.87	2,615,370	16.5
2006	109,704,171.83	41,728,771	33,368,908	0.2414	104,858,349	35.84	2,925,408	15.5
2007	105,430,196.90	37,530,123	30,011,409	0.2259	102,830,639	36.82	2,792,462	14.5
2008	113,170,328.99	37,517,702	30,001,477	0.2104	112,593,138	37.81	2,977,879	13.5
2009	78,061,869.45	23,966,623	19,165,195	0.1949	79,192,761	38.80	2,041,080	12.5
2010	126,426,207.82	35,715,237	28,560,114	0.1793	130,736,908	39.79	3,285,485	11.5

Enbridge Gas Distribution

Account #: 473.02 - Distribution - Services - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S3
ASL: 55
Net Salvage: -26%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2011	115,922,136.62	29,902,940	23,912,241	0.1637	122,149,651	40.79	2,994,775	10.5
2012	138,256,592.59	32,269,515	25,804,701	0.1481	148,398,605	41.78	3,551,508	9.5
2013	138,646,957.73	28,955,234	23,154,397	0.1325	151,540,770	42.78	3,542,086	8.5
2014	132,102,041.38	24,343,149	19,466,289	0.1170	146,982,284	43.78	3,357,143	7.5
2015	150,761,600.30	24,077,653	19,253,982	0.1014	170,705,635	44.78	3,811,970	6.5
2016	148,370,557.88	20,050,374	16,033,520	0.0858	170,913,383	45.78	3,733,263	5.5
2017	142,742,100.37	15,782,558	12,620,710	0.0702	167,234,337	46.78	3,574,823	4.5
2018	151,710,925.20	13,046,613	10,432,879	0.0546	180,722,886	47.78	3,782,306	3.5
2019	180,810,000.48	11,106,452	8,881,406	0.0390	218,939,194	48.78	4,488,194	2.5
2020	164,306,151.39	6,055,611	4,842,441	0.0234	202,183,309	49.78	4,061,444	1.5
2021	345,114,099.71	4,239,802	3,390,408	0.0078	431,453,357	50.78	8,496,331	0.5
TOTAL	4,458,883,264.63	1,731,773,793	1,384,833,504		4,233,359,410		121,567,635	

COMPOSITE ANNUAL ACCRUAL RATE	2.73%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	16.26
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	35.75

Enbridge Gas Distribution

Account #: 474.00 - Distribution - Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1997	7,933,012.78	7,774,353	2,517,907	0.3174	5,415,106	0.50	5,415,106	24.5
1998	9,189,350.75	8,637,990	2,797,616	0.3044	6,391,735	1.50	4,261,157	23.5
1999	10,501,133.78	9,451,020	3,060,935	0.2915	7,440,199	2.50	2,976,079	22.5
2000	12,787,095.65	10,996,902	3,561,605	0.2785	9,225,490	3.50	2,635,854	21.5
2001	14,943,687.85	12,253,824	3,968,689	0.2656	10,974,999	4.50	2,438,889	20.5
2002	12,164,610.21	9,488,396	3,073,040	0.2526	9,091,570	5.50	1,653,013	19.5
2003	14,508,078.70	10,735,978	3,477,099	0.2397	11,030,980	6.50	1,697,074	18.5
2004	7,119,777.11	4,983,844	1,614,135	0.2267	5,505,642	7.50	734,086	17.5
2005	13,256,161.50	8,749,067	2,833,591	0.2138	10,422,571	8.50	1,226,185	16.5
2006	15,434,123.63	9,569,157	3,099,196	0.2008	12,334,927	9.50	1,298,413	15.5
2007	15,300,290.99	8,874,169	2,874,108	0.1878	12,426,183	10.50	1,183,446	14.5
2008	15,283,142.09	8,252,897	2,672,895	0.1749	12,610,248	11.50	1,096,543	13.5
2009	16,523,613.11	8,261,807	2,675,780	0.1619	13,847,833	12.50	1,107,827	12.5
2010	16,711,002.41	7,687,061	2,489,635	0.1490	14,221,367	13.50	1,053,435	11.5
2011	19,593,594.55	8,229,310	2,665,255	0.1360	16,928,339	14.50	1,167,472	10.5
2012	21,890,642.77	8,318,444	2,694,124	0.1231	19,196,519	15.50	1,238,485	9.5
2013	24,710,279.37	8,401,495	2,721,022	0.1101	21,989,258	16.50	1,332,682	8.5
2014	22,900,250.01	6,870,075	2,225,035	0.0972	20,675,215	17.50	1,181,441	7.5
2015	26,425,603.78	6,870,657	2,225,224	0.0842	24,200,380	18.50	1,308,129	6.5
2016	29,212,083.62	6,426,658	2,081,424	0.0713	27,130,659	19.50	1,391,316	5.5
2017	25,297,702.47	4,553,586	1,474,786	0.0583	23,822,916	20.50	1,162,093	4.5
2018	25,759,823.63	3,606,375	1,168,009	0.0453	24,591,814	21.50	1,143,805	3.5
2019	28,900,291.78	2,890,029	936,004	0.0324	27,964,288	22.50	1,242,857	2.5
2020	32,205,594.49	1,932,336	625,832	0.0194	31,579,762	23.50	1,343,820	1.5
2021	50,319,983.97	1,006,400	325,946	0.0065	49,994,038	24.50	2,040,573	0.5

Enbridge Gas Distribution

Account #: 474.00 - Distribution - Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	488,870,931.00	184,821,829	59,858,893		429,012,038		43,329,779	

COMPOSITE ANNUAL ACCRUAL RATE	8.86%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.12
COMPOSITE AVERAGE AGE (YEARS)	9.45
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	15.55

Enbridge Gas Distribution

Account #: 475.00 - Distribution - Mains - Envision

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2004	29,459,720.88	20,621,805	13,304,715	0.4516	16,155,006	7.50	2,154,001	17.5
2005	18,650,617.10	12,309,407	7,941,747	0.4258	10,708,870	8.50	1,259,867	16.5
2006	18,244,834.93	11,311,798	7,298,112	0.4000	10,946,723	9.50	1,152,287	15.5
2007	15,875,281.79	9,207,663	5,940,573	0.3742	9,934,709	10.50	946,163	14.5
2008	11,772,203.07	6,356,990	4,101,384	0.3484	7,670,819	11.50	667,028	13.5
2009	17,976,461.62	8,988,231	5,799,000	0.3226	12,177,461	12.50	974,197	12.5
2010	11,575,661.85	5,324,804	3,435,442	0.2968	8,140,220	13.50	602,979	11.5
2011	9,694,732.90	4,071,788	2,627,024	0.2710	7,067,709	14.50	487,428	10.5
2012	10,460,599.46	3,975,028	2,564,597	0.2452	7,896,003	15.50	509,420	9.5
2013	9,928,403.50	3,375,657	2,177,897	0.2194	7,750,507	16.50	469,728	8.5
2014	9,730,838.73	2,919,252	1,883,434	0.1936	7,847,405	17.50	448,423	7.5
2015	10,608,447.06	2,758,196	1,779,525	0.1677	8,828,922	18.50	477,239	6.5
2016	7,279,412.00	1,601,471	1,033,232	0.1419	6,246,180	19.50	320,317	5.5
2017	7,461.53	1,343	867	0.1161	6,595	20.50	322	4.5
TOTAL	181,264,676.42	92,823,432	59,887,548		121,377,128		10,469,397	

COMPOSITE ANNUAL ACCRUAL RATE	5.78%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	12.80
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	12.20

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1894	31.00	44	33	0.7528	11	0.00	11	127.5
1900	24.14	34	26	0.7529	8	0.00	8	121.5
1901	882.13	1,253	943	0.7529	309	0.00	309	120.5
1904	475.41	675	508	0.7529	167	0.00	167	117.5
1905	2,239.37	3,180	2,394	0.7529	786	0.00	786	116.5
1909	2,557.09	3,631	2,734	0.7529	897	0.00	897	112.5
1910	11,960.68	16,984	12,788	0.7529	4,196	0.00	4,196	111.5
1911	48.92	69	52	0.7529	17	0.00	17	110.5
1912	295.91	420	316	0.7529	104	0.00	104	109.5
1914	18,551.62	26,343	19,835	0.7529	6,509	0.00	6,509	107.5
1915	10.33	15	11	0.7526	4	0.00	4	106.5
1917	20.67	29	22	0.7529	7	0.00	7	104.5
1918	5,722.35	8,126	6,118	0.7529	2,008	0.00	2,008	103.5
1919	2,272.46	3,227	2,430	0.7529	797	0.00	797	102.5
1920	2,640.01	3,749	2,823	0.7529	926	0.00	926	101.5
1921	4,778.59	6,786	5,109	0.7529	1,677	0.00	1,677	100.5
1924	3,720.56	5,283	3,978	0.7529	1,305	0.00	1,305	97.5
1925	229,889.97	326,444	245,788	0.7529	80,656	0.00	80,656	96.5
1926	5,925.59	8,414	6,335	0.7529	2,079	0.00	2,079	95.5
1927	265,632.65	377,198	284,003	0.7529	93,196	0.00	93,196	94.5
1928	208,696.81	296,349	223,129	0.7529	73,220	0.00	73,220	93.5
1929	11,693.67	16,516	12,435	0.7489	4,170	0.50	4,170	92.5
1930	32,004.54	45,177	34,015	0.7485	11,432	0.55	11,432	91.5
1931	299,587.70	422,097	317,808	0.7471	107,607	0.71	107,607	90.5
1932	807.04	1,134	854	0.7454	292	0.91	292	89.5
1933	4,300.46	6,030	4,540	0.7435	1,566	1.12	1,397	88.5

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1934	4,519.92	6,322	4,760	0.7416	1,658	1.34	1,242	87.5
1935	37,493.72	52,300	39,378	0.7396	13,863	1.56	8,910	86.5
1936	49,203.14	68,438	51,529	0.7375	18,339	1.79	10,265	85.5
1937	98,402.01	136,464	102,747	0.7353	36,984	2.02	18,280	84.5
1938	49,373.63	68,260	51,395	0.7331	18,716	2.26	8,269	83.5
1939	118,259.02	162,977	122,709	0.7307	45,218	2.51	18,042	82.5
1940	46,288.16	63,588	47,877	0.7284	17,852	2.74	6,504	81.5
1941	92,337.02	126,428	95,191	0.7260	35,928	2.99	12,029	80.5
1942	3,659.02	4,993	3,759	0.7235	1,437	3.23	445	79.5
1943	10,116.06	13,756	10,357	0.7210	4,008	3.47	1,153	78.5
1944	10,235.69	13,869	10,442	0.7184	4,092	3.72	1,100	77.5
1945	3,439.76	4,644	3,497	0.7159	1,388	3.96	350	76.5
1946	76,563.83	102,993	77,546	0.7133	31,174	4.20	7,425	75.5
1947	4,547.68	6,095	4,589	0.7106	1,869	4.44	421	74.5
1948	19,057.29	25,442	19,156	0.7079	7,905	4.68	1,690	73.5
1949	5,248.90	6,980	5,255	0.7051	2,198	4.92	447	72.5
1950	33,682.36	44,609	33,588	0.7022	14,241	5.16	2,760	71.5
1951	187,806.18	247,704	186,503	0.6993	80,182	5.40	14,842	70.5
1952	96,014.69	126,092	94,938	0.6963	41,403	5.65	7,329	69.5
1953	340,239.03	444,820	334,916	0.6932	148,223	5.90	25,118	68.5
1954	294,801.17	383,611	288,831	0.6900	129,787	6.16	21,070	67.5
1955	438,970.93	568,413	427,973	0.6866	195,366	6.43	30,403	66.5
1956	1,541,821.69	1,986,222	1,495,479	0.6831	693,908	6.70	103,571	65.5
1957	10,729,456.30	13,747,496	10,350,851	0.6794	4,884,977	6.98	699,563	64.5
1958	30,571,577.15	38,948,297	29,325,195	0.6755	14,086,445	7.28	1,935,780	63.5
1959	36,689,474.62	46,462,310	34,982,693	0.6715	17,116,361	7.58	2,257,376	62.5

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1960	14,236,454.72	17,914,525	13,488,316	0.6672	6,727,450	7.90	851,567	61.5
1961	16,558,259.61	20,697,088	15,583,381	0.6628	7,929,348	8.23	963,417	60.5
1962	22,326,935.42	27,711,018	20,864,352	0.6581	10,839,896	8.57	1,264,259	59.5
1963	17,939,644.78	22,100,067	16,639,720	0.6532	8,834,575	8.93	989,120	58.5
1964	10,809,823.82	13,212,190	9,947,804	0.6481	5,402,146	9.30	580,650	57.5
1965	11,552,779.81	14,003,341	10,543,483	0.6427	5,861,465	9.69	604,905	56.5
1966	13,155,954.88	15,807,443	11,901,839	0.6371	6,779,617	10.09	671,870	55.5
1967	21,089,710.60	25,107,227	18,903,890	0.6312	11,043,499	10.51	1,051,112	54.5
1968	16,570,366.48	19,536,010	14,709,174	0.6251	8,820,746	10.94	806,472	53.5
1969	19,069,384.95	22,253,532	16,755,268	0.6188	10,323,258	11.38	906,901	52.5
1970	18,144,678.96	20,948,185	15,772,438	0.6122	9,993,006	11.84	843,792	51.5
1971	19,088,686.42	21,791,026	16,407,035	0.6053	10,698,899	12.32	868,620	50.5
1972	18,547,822.32	20,924,844	15,754,864	0.5982	10,583,043	12.81	826,465	49.5
1973	20,175,254.05	22,480,376	16,926,065	0.5908	11,722,795	13.31	880,876	48.5
1974	19,756,390.79	21,729,898	16,361,010	0.5832	11,693,065	13.82	845,840	47.5
1975	13,208,700.90	14,332,412	10,791,249	0.5753	7,965,107	14.35	554,943	46.5
1976	16,540,071.96	17,694,663	13,322,776	0.5672	10,164,126	14.89	682,424	45.5
1977	16,981,103.98	17,899,706	13,477,158	0.5589	10,636,009	15.45	688,543	44.5
1978	14,997,558.70	15,566,554	11,720,467	0.5503	9,576,067	16.01	598,050	43.5
1979	16,758,008.25	17,115,720	12,886,875	0.5415	10,909,497	16.59	657,646	42.5
1980	14,731,887.84	14,795,759	11,140,115	0.5325	9,779,166	17.18	569,364	41.5
1981	14,323,398.40	14,135,993	10,643,360	0.5233	9,695,865	17.77	545,557	40.5
1982	13,332,728.51	12,920,679	9,728,319	0.5138	9,204,156	18.38	500,804	39.5
1983	21,426,118.42	20,373,643	15,339,850	0.5042	15,085,238	18.99	794,203	38.5
1984	19,519,604.05	18,197,238	13,701,178	0.4943	14,016,659	19.62	714,421	37.5
1985	14,617,325.80	13,349,283	10,051,025	0.4842	10,705,577	20.25	528,584	36.5

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1986	14,706,593.66	13,145,826	9,897,838	0.4740	10,985,525	20.90	525,748	35.5
1987	31,059,637.62	27,150,048	20,441,984	0.4635	23,662,702	21.54	1,098,316	34.5
1988	19,343,553.30	16,519,694	12,438,111	0.4528	15,029,734	22.20	676,967	33.5
1989	39,248,495.27	32,715,021	24,631,998	0.4420	31,100,866	22.87	1,360,103	32.5
1990	40,677,356.96	33,058,174	24,890,367	0.4309	32,871,480	23.54	1,396,452	31.5
1991	74,523,446.21	58,985,208	44,411,510	0.4197	61,411,783	24.22	2,535,688	30.5
1992	27,487,891.82	21,164,531	15,935,330	0.4083	23,097,476	24.91	927,403	29.5
1993	26,003,959.82	19,452,902	14,646,600	0.3967	22,279,022	25.60	870,312	28.5
1994	43,932,383.15	31,888,357	24,009,581	0.3849	38,374,403	26.30	1,459,162	27.5
1995	39,499,790.13	27,779,222	20,915,705	0.3729	35,173,997	27.01	1,302,413	26.5
1996	36,452,530.54	24,801,162	18,673,446	0.3608	33,089,148	27.72	1,193,643	25.5
1997	26,797,860.90	17,609,822	13,258,897	0.3484	24,794,065	28.44	871,744	24.5
1998	35,597,604.06	22,553,901	16,981,424	0.3359	33,567,174	29.17	1,150,781	23.5
1999	43,830,609.47	26,723,719	20,120,989	0.3233	42,118,477	29.90	1,408,530	22.5
2000	34,427,768.62	20,157,783	15,177,324	0.3105	33,710,108	30.64	1,100,105	21.5
2001	42,096,541.71	23,616,187	17,781,247	0.2975	41,995,842	31.39	1,337,898	20.5
2002	44,496,198.90	23,858,452	17,963,654	0.2843	45,220,948	32.14	1,406,909	19.5
2003	20,542,914.89	10,499,191	7,905,116	0.2710	21,265,823	32.90	646,370	18.5
2004	25,714,395.59	12,489,262	9,403,493	0.2575	27,110,949	33.66	805,335	17.5
2005	40,386,777.13	18,578,492	13,988,234	0.2439	43,360,989	34.43	1,259,278	16.5
2006	54,401,891.70	23,613,180	17,778,983	0.2301	59,471,703	35.21	1,689,136	15.5
2007	86,472,776.23	35,265,312	26,552,178	0.2162	96,239,164	35.99	2,674,203	14.5
2008	50,243,100.21	19,159,116	14,425,401	0.2022	56,919,801	36.77	1,547,927	13.5
2009	46,101,813.60	16,346,913	12,308,019	0.1880	53,156,556	37.56	1,415,288	12.5
2010	28,606,114.10	9,371,083	7,055,734	0.1737	33,564,948	38.35	875,253	11.5
2011	56,729,296.73	17,038,819	12,828,974	0.1593	67,726,628	39.14	1,730,299	10.5

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -42%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2012	29,117,111.47	7,945,441	5,982,331	0.1447	35,363,968	39.94	885,519	9.5
2013	78,911,056.58	19,347,181	14,567,000	0.1300	97,486,700	40.73	2,393,502	8.5
2014	147,219,903.94	31,983,882	24,081,504	0.1152	184,970,760	41.52	4,454,839	7.5
2015	68,235,901.61	12,903,946	9,715,719	0.1003	87,179,261	42.31	2,060,580	6.5
2016	458,760,681.23	73,743,330	55,523,288	0.0852	595,916,879	43.09	13,830,751	5.5
2017	109,428,743.25	14,461,680	10,888,578	0.0701	144,500,237	43.85	3,295,188	4.5
2018	196,754,404.11	20,332,924	15,309,192	0.0548	264,082,062	44.59	5,922,065	3.5
2019	141,819,538.75	10,534,949	7,932,039	0.0394	193,451,706	45.29	4,271,452	2.5
2020	178,851,789.99	8,038,300	6,052,247	0.0238	247,917,295	45.89	5,402,143	1.5
2021	363,811,882.15	5,530,162	4,163,804	0.0081	512,449,069	46.21	11,089,893	0.5
TOTAL	3,320,418,328.48	1,396,363,922	1,051,359,036		3,663,634,991		112,249,759	

COMPOSITE ANNUAL ACCRUAL RATE	3.38%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	16.91
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	34.94

Enbridge Gas Distribution

Account #: 475.30 - Distribution - Mains - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -38%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1958	807.98	1,005	742	0.6653	373	6.94	54	63.5
1967	46.86	54	40	0.6139	25	11.01	2	54.5
1968	156,584.48	177,636	131,099	0.6067	84,988	11.58	7,339	53.5
1970	9,247.98	10,226	7,547	0.5914	5,215	12.77	408	51.5
1971	138,390.05	150,964	111,414	0.5834	79,564	13.39	5,944	50.5
1972	343,888.32	369,884	272,981	0.5752	201,585	14.01	14,390	49.5
1973	2,440,656.75	2,587,143	1,909,356	0.5669	1,458,750	14.64	99,639	48.5
1974	4,605,656.70	4,808,799	3,548,977	0.5584	2,806,830	15.28	183,682	47.5
1975	4,675,574.02	4,805,780	3,546,749	0.5497	2,905,543	15.93	182,378	46.5
1976	6,423,773.65	6,496,094	4,794,230	0.5408	4,070,578	16.59	245,349	45.5
1977	8,224,377.01	8,177,561	6,035,182	0.5318	5,314,458	17.26	307,878	44.5
1978	11,301,973.90	11,041,963	8,149,159	0.5225	7,447,565	17.94	415,055	43.5
1979	18,397,967.81	17,649,900	13,025,931	0.5131	12,363,264	18.64	663,415	42.5
1980	34,491,240.57	32,467,305	23,961,433	0.5034	23,636,479	19.34	1,222,150	41.5
1981	25,464,108.56	23,501,837	17,344,762	0.4936	17,795,707	20.06	887,279	40.5
1982	25,607,426.94	23,154,848	17,088,679	0.4836	18,249,570	20.78	878,070	39.5
1983	25,357,560.44	22,445,372	16,565,073	0.4734	18,428,360	21.52	856,202	38.5
1984	31,785,627.19	27,518,133	20,308,858	0.4630	23,555,307	22.28	1,057,460	37.5
1985	25,074,148.58	21,213,009	15,655,568	0.4524	18,946,757	23.04	822,405	36.5
1986	25,595,652.42	21,140,784	15,602,265	0.4417	19,719,736	23.81	828,095	35.5
1987	31,498,975.80	25,374,828	18,727,062	0.4308	24,741,524	24.60	1,005,731	34.5
1988	29,513,727.35	23,165,689	17,096,680	0.4198	23,632,264	25.40	930,467	33.5
1989	43,234,172.45	33,028,891	24,375,893	0.4086	35,287,265	26.21	1,346,443	32.5
1990	33,573,751.34	24,935,676	18,402,961	0.3972	27,928,816	27.03	1,033,305	31.5
1991	44,329,393.44	31,971,274	23,595,354	0.3857	37,579,209	27.86	1,348,888	30.5
1992	42,316,315.53	29,599,086	21,844,638	0.3741	36,551,877	28.70	1,273,539	29.5

Enbridge Gas Distribution

Account #: 475.30 - Distribution - Mains - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -38%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1993	45,660,367.03	30,934,142	22,829,932	0.3623	40,181,374	29.55	1,359,634	28.5
1994	71,406,330.17	46,791,164	34,532,689	0.3504	64,008,047	30.41	2,104,549	27.5
1995	84,083,522.93	53,213,395	39,272,406	0.3385	76,762,855	31.28	2,453,666	26.5
1996	80,697,145.79	49,245,282	36,343,871	0.3264	75,018,190	32.17	2,332,288	25.5
1997	81,189,401.12	47,695,322	35,199,973	0.3142	76,841,400	33.05	2,324,786	24.5
1998	87,155,125.69	49,198,574	36,309,399	0.3019	83,964,674	33.95	2,473,212	23.5
1999	88,130,303.58	47,711,346	35,211,800	0.2895	86,408,019	34.85	2,479,128	22.5
2000	83,554,050.58	43,290,422	31,949,081	0.2771	83,355,509	35.77	2,330,611	21.5
2001	86,814,041.80	42,948,489	31,696,729	0.2646	88,106,649	36.68	2,401,769	20.5
2002	70,173,181.01	33,065,731	24,403,082	0.2520	72,435,908	37.61	1,926,011	19.5
2003	69,467,695.34	31,092,326	22,946,675	0.2394	72,918,745	38.54	1,892,021	18.5
2004	49,483,656.96	20,973,953	15,479,140	0.2267	52,808,306	39.48	1,337,702	17.5
2005	71,346,819.36	28,541,717	21,064,281	0.2139	77,394,330	40.42	1,914,799	16.5
2006	130,542,562.61	49,103,523	36,239,250	0.2012	143,909,486	41.37	3,478,958	15.5
2007	117,078,848.28	41,233,209	30,430,822	0.1883	131,137,989	42.32	3,098,942	14.5
2008	100,171,111.97	32,871,299	24,259,588	0.1755	113,976,547	43.27	2,633,922	13.5
2009	111,486,378.79	33,898,968	25,018,025	0.1626	128,833,178	44.23	2,912,701	12.5
2010	101,185,681.78	28,324,271	20,903,803	0.1497	118,732,438	45.19	2,627,172	11.5
2011	79,567,412.20	20,348,381	15,017,458	0.1368	94,785,571	46.16	2,053,430	10.5
2012	92,279,144.86	21,363,767	15,766,830	0.1238	111,578,390	47.13	2,367,579	9.5
2013	97,943,602.25	20,298,889	14,980,931	0.1108	120,181,240	48.10	2,498,669	8.5
2014	94,463,784.26	17,282,835	12,755,031	0.0978	117,604,991	49.07	2,396,649	7.5
2015	88,837,469.15	14,092,860	10,400,775	0.0848	112,194,933	50.04	2,241,909	6.5
2016	118,935,839.98	15,971,908	11,787,544	0.0718	152,343,915	51.02	2,985,998	5.5
2017	134,545,796.71	14,789,439	10,914,862	0.0588	174,758,337	52.00	3,361,060	4.5
2018	123,856,432.62	10,593,715	7,818,345	0.0457	163,103,532	52.97	3,079,171	3.5

Enbridge Gas Distribution

Account #: 475.30 - Distribution - Mains - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -38%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2019	121,499,902.69	7,426,497	5,480,883	0.0327	162,188,983	53.94	3,006,667	2.5
2020	143,054,172.92	5,249,371	3,874,127	0.0196	193,540,632	54.91	3,524,626	1.5
2021	380,935,199.57	4,663,739	3,441,920	0.0065	522,248,655	55.86	9,349,352	0.5
TOTAL	3,480,106,028.12	1,258,008,275	928,431,883		3,874,114,436		94,562,546	

COMPOSITE ANNUAL ACCRUAL RATE 2.72%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.27

COMPOSITE AVERAGE AGE (YEARS) 15.18

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 42.03

Enbridge Gas Distribution

Account #: 476.00 - Distribution - Company NGV Compressor Stations
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 17
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	942,259.45	920,013	942,259	1.0000	0	0.74	0	30.5
1994	330,634.49	316,504	330,634	1.0000	0	1.23	0	27.5
1996	29,028.16	27,345	29,028	1.0000	0	1.57	0	25.5
1997	296,027.20	276,337	296,027	1.0000	0	1.75	0	24.5
1998	88,211.29	81,516	88,211	1.0000	0	1.93	0	23.5
2001	364,723.75	324,297	364,724	1.0000	0	2.56	0	20.5
2005	235,141.40	192,391	235,141	1.0000	0	3.67	0	16.5
2010	354,709.77	235,433	354,710	1.0000	0	5.83	0	11.5
2013	268,244.94	140,555	250,063	0.9322	18,182	7.72	2,355	8.5
2014	247,673.77	116,333	206,969	0.8356	40,705	8.47	4,807	7.5
2015	156,531.87	64,528	114,803	0.7334	41,729	9.27	4,503	6.5
2016	200,621.12	70,649	125,693	0.6265	74,928	10.12	7,405	5.5
2017	711,674.46	206,434	367,270	0.5161	344,405	11.01	31,271	4.5
2018	2,151,976.17	487,597	867,489	0.4031	1,284,487	11.95	107,515	3.5
2019	1,374,242.78	222,938	396,631	0.2886	977,612	12.91	75,722	2.5
2020	771,588.19	75,177	133,748	0.1733	637,840	13.90	45,903	1.5
2021	1,355,413.93	44,030	78,334	0.0578	1,277,080	14.89	85,757	0.5
TOTAL	9,878,702.74	3,802,077	5,181,735		4,696,968		365,237	

COMPOSITE ANNUAL ACCRUAL RATE	3.70%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	8.66
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	9.67

Enbridge Gas Distribution

Account #: 477.00 - Distribution - Measuring and Regulating Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -9%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1959	196,007.64	203,415	213,648	1.0000	0	3.14	0	62.5
1969	1,232,838.22	1,208,773	1,311,906	0.9763	31,888	5.86	5,438	52.5
1970	203,403.32	198,056	214,954	0.9695	6,756	6.15	1,098	51.5
1971	581,568.69	562,177	610,142	0.9625	23,768	6.44	3,688	50.5
1972	910,009.11	872,970	947,453	0.9552	44,457	6.74	6,592	49.5
1973	339,752.34	323,313	350,899	0.9475	19,431	7.05	2,755	48.5
1974	665,094.42	627,573	681,118	0.9395	43,835	7.37	5,947	47.5
1975	750,684.33	702,031	761,929	0.9312	56,317	7.70	7,316	46.5
1976	926,082.87	857,930	931,129	0.9224	78,301	8.03	9,745	45.5
1977	1,506,679.30	1,381,968	1,499,878	0.9133	142,402	8.38	16,989	44.5
1978	1,409,834.99	1,279,613	1,388,790	0.9037	147,930	8.74	16,925	43.5
1979	1,397,378.07	1,254,302	1,361,320	0.8938	161,822	9.11	17,765	42.5
1980	1,645,791.15	1,460,063	1,584,636	0.8833	209,276	9.49	22,054	41.5
1981	17,279,686.38	15,141,123	16,432,973	0.8725	2,401,885	9.88	243,103	40.5
1982	2,887,513.76	2,497,319	2,710,392	0.8612	436,998	10.28	42,501	39.5
1983	2,127,312.40	1,814,665	1,969,493	0.8494	349,277	10.70	32,658	38.5
1984	4,927,795.71	4,142,904	4,496,380	0.8371	874,918	11.12	78,687	37.5
1985	3,919,158.61	3,244,799	3,521,647	0.8244	750,236	11.55	64,936	36.5
1986	3,568,962.63	2,907,489	3,155,558	0.8112	734,611	12.00	61,226	35.5
1987	6,689,897.31	5,357,932	5,815,075	0.7975	1,476,913	12.45	118,594	34.5
1988	6,139,081.48	4,829,295	5,241,334	0.7833	1,450,265	12.92	112,263	33.5
1989	7,046,752.77	5,439,415	5,903,509	0.7686	1,777,451	13.39	132,715	32.5
1990	12,245,184.50	9,265,500	10,056,039	0.7534	3,291,212	13.88	237,174	31.5
1991	10,773,448.73	7,982,371	8,663,432	0.7377	3,079,627	14.37	214,320	30.5
1992	7,962,265.90	5,770,240	6,262,561	0.7216	2,416,309	14.87	162,493	29.5
1993	10,823,467.72	7,662,680	8,316,465	0.7049	3,481,114	15.38	226,355	28.5

Enbridge Gas Distribution

Account #: 477.00 - Distribution - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -9%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1994	14,079,112.59	9,725,036	10,554,782	0.6878	4,791,450	15.90	301,437	27.5
1995	15,281,977.36	10,285,030	11,162,556	0.6701	5,494,800	16.42	334,668	26.5
1996	18,447,602.03	12,079,368	13,109,988	0.6520	6,997,898	16.95	412,892	25.5
1997	13,222,441.97	8,410,413	9,127,995	0.6333	5,284,467	17.48	302,241	24.5
1998	22,509,318.46	13,884,859	15,069,525	0.6142	9,465,632	18.03	525,124	23.5
1999	26,109,355.04	15,590,615	16,920,817	0.5946	11,538,380	18.57	621,291	22.5
2000	27,857,152.92	16,070,916	17,442,097	0.5744	12,922,200	19.12	675,777	21.5
2001	14,352,001.12	7,982,275	8,663,328	0.5538	6,980,353	19.68	354,766	20.5
2002	12,545,874.76	6,711,389	7,284,009	0.5327	6,390,994	20.23	315,872	19.5
2003	15,114,471.31	7,756,895	8,418,718	0.5110	8,056,056	20.79	387,461	18.5
2004	19,955,293.97	9,797,273	10,633,182	0.4889	11,118,088	21.35	520,696	17.5
2005	17,661,309.06	8,268,982	8,974,497	0.4662	10,276,330	21.91	468,955	16.5
2006	21,974,682.05	9,776,855	10,611,022	0.4430	13,341,381	22.47	593,647	15.5
2007	21,410,214.52	9,015,963	9,785,210	0.4193	13,551,923	23.03	588,392	14.5
2008	26,093,263.92	10,352,863	11,236,176	0.3951	17,205,482	23.59	729,430	13.5
2009	25,951,245.67	9,650,748	10,474,156	0.3703	17,812,701	24.14	737,948	12.5
2010	16,637,831.58	5,764,064	6,255,858	0.3450	11,879,379	24.68	481,298	11.5
2011	22,106,903.59	7,083,937	7,688,343	0.3191	16,408,182	25.22	650,692	10.5
2012	28,867,818.40	8,482,924	9,206,693	0.2926	22,259,229	25.74	864,819	9.5
2013	27,156,145.75	7,241,566	7,859,421	0.2655	21,740,778	26.24	828,406	8.5
2014	36,553,439.27	8,730,545	9,475,440	0.2378	30,367,808	26.73	1,136,203	7.5
2015	41,726,961.12	8,777,548	9,526,454	0.2095	35,955,933	27.18	1,322,839	6.5
2016	122,074,437.89	22,114,658	24,001,495	0.1804	109,059,642	27.59	3,952,465	5.5
2017	51,923,735.00	7,849,706	8,519,448	0.1505	48,077,424	27.95	1,720,413	4.5
2018	27,334,249.67	3,288,825	3,569,430	0.1198	26,224,902	28.21	929,717	3.5
2019	28,257,924.31	2,498,517	2,711,692	0.0880	28,089,445	28.32	991,879	2.5

Enbridge Gas Distribution

Account #: 477.00 - Distribution - Measuring and Regulating Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -9%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2020	64,233,414.65	3,543,539	3,845,876	0.0549	66,168,546	28.14	2,351,614	1.5
2021	63,362,267.28	1,249,920	1,356,564	0.0196	67,708,307	27.13	2,495,909	0.5
TOTAL	950,956,097.61	338,973,144	367,887,432		668,654,715		27,440,187	

COMPOSITE ANNUAL ACCRUAL RATE	2.89%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.39
COMPOSITE AVERAGE AGE (YEARS)	13.23
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	23.25

Enbridge Gas Inc.

Account #: 477.01 - Distribution - Customer M&R Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1964	1,195.15	1,184	1,074	0.8986	121	0.56	121	57.5
1968	7,264.20	7,081	6,425	0.8844	839	1.38	607	53.5
1970	51,709.38	49,911	45,285	0.8758	6,425	1.86	3,463	51.5
1971	4,739.48	4,551	4,129	0.8712	611	2.10	291	50.5
1972	9,572.52	9,141	8,294	0.8664	1,279	2.34	547	49.5
1975	422.87	397	360	0.8514	63	3.05	21	46.5
1976	64,825.71	60,448	54,845	0.8460	9,981	3.30	3,029	45.5
1977	51,919.59	48,096	43,638	0.8405	8,282	3.54	2,341	44.5
1978	130,934.35	120,446	109,281	0.8346	21,653	3.79	5,716	43.5
1979	601,286.63	548,990	498,101	0.8284	103,185	4.05	25,487	42.5
1980	509,213.82	461,183	418,434	0.8217	90,780	4.32	21,004	41.5
1981	5,356,566.40	4,809,048	4,363,276	0.8146	993,290	4.61	215,418	40.5
1982	515,597.60	458,515	416,013	0.8069	99,584	4.92	20,251	39.5
1983	393,928.62	346,708	314,571	0.7985	79,358	5.24	15,134	38.5
1984	736,121.88	640,618	581,236	0.7896	154,886	5.59	27,705	37.5
1985	1,146,838.66	985,865	894,480	0.7800	252,358	5.96	42,343	36.5
1986	1,513,563.83	1,283,847	1,164,842	0.7696	348,722	6.35	54,900	35.5
1987	9,491,461.63	7,934,985	7,199,457	0.7585	2,292,004	6.77	338,688	34.5
1988	362,409.54	298,255	270,608	0.7467	91,801	7.21	12,740	33.5
1989	418,696.07	338,773	307,371	0.7341	111,325	7.67	14,519	32.5
1990	613,558.37	487,426	442,245	0.7208	171,314	8.15	21,017	31.5
1991	1,123,804.07	875,337	794,199	0.7067	329,605	8.66	38,072	30.5
1992	1,682,033.42	1,282,690	1,163,792	0.6919	518,241	9.18	56,427	29.5
1993	2,026,271.87	1,510,535	1,370,517	0.6764	655,755	9.73	67,391	28.5
1994	667,459.17	485,645	440,628	0.6602	226,831	10.30	22,032	27.5
1995	4,080,318.58	2,892,895	2,624,741	0.6433	1,455,578	10.88	133,819	26.5

Enbridge Gas Inc.

Account #: 477.01 - Distribution - Customer M&R Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1996	6,561,650.27	4,525,258	4,105,792	0.6257	2,455,858	11.48	214,015	25.5
1997	752,765.01	504,065	457,341	0.6075	295,424	12.09	24,439	24.5
1998	1,208,244.49	784,022	711,348	0.5887	496,897	12.72	39,078	23.5
1999	1,355,641.34	850,677	771,825	0.5693	583,817	13.36	43,712	22.5
2000	1,081,496.63	654,825	594,126	0.5494	487,370	14.01	34,790	21.5
2001	708,667.59	413,026	374,741	0.5288	333,927	14.67	22,757	20.5
2002	2,700,373.23	1,510,967	1,370,909	0.5077	1,329,464	15.35	86,610	19.5
2003	3,285,837.20	1,760,063	1,596,915	0.4860	1,688,922	16.04	105,311	18.5
2004	2,677,178.61	1,368,476	1,241,626	0.4638	1,435,552	16.74	85,778	17.5
2005	1,436,766.50	698,383	633,646	0.4410	803,120	17.45	46,037	16.5
2006	7,709,627.46	3,549,665	3,220,631	0.4177	4,488,996	18.16	247,124	15.5
2007	1,951,520.01	847,344	768,800	0.3939	1,182,720	18.89	62,594	14.5
2008	10,043,243.77	4,091,856	3,712,564	0.3697	6,330,680	19.64	322,418	13.5
2009	8,335,343.56	3,168,394	2,874,702	0.3449	5,460,642	20.38	267,879	12.5
2010	500,125.32	176,189	159,857	0.3196	340,268	21.14	16,093	11.5
2011	1,708,429.37	553,464	502,161	0.2939	1,206,268	21.91	55,052	10.5
2012	1,514,115.54	446,884	405,460	0.2678	1,108,655	22.69	48,866	9.5
2013	3,015,275.30	801,668	727,358	0.2412	2,287,918	23.47	97,480	8.5
2014	4,845,360.23	1,144,235	1,038,171	0.2143	3,807,189	24.26	156,937	7.5
2015	1,925,850.02	396,744	359,968	0.1869	1,565,882	25.05	62,505	6.5
2016	2,275,352.09	399,240	362,233	0.1592	1,913,119	25.85	74,021	5.5
2017	10,255,924.80	1,482,236	1,344,841	0.1311	8,911,084	26.64	334,544	4.5
2018	4,380,781.50	495,920	449,951	0.1027	3,930,831	27.42	143,368	3.5
2019	3,059,725.72	249,348	226,235	0.0739	2,833,490	28.18	100,560	2.5
2020	3,626,193.86	179,030	162,434	0.0448	3,463,759	28.88	119,928	1.5
2021	25,249,778.31	422,121	382,993	0.0152	24,866,786	29.41	845,572	0.5

Enbridge Gas Inc.

Account #: 477.01 - Distribution - Customer M&R Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	143,726,981.14	57,416,667	52,094,469		91,632,512		4,800,551	

COMPOSITE ANNUAL ACCRUAL RATE	3.34%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.36
COMPOSITE AVERAGE AGE (YEARS)	14.92
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	19.36

Enbridge Gas Distribution

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1965	11,515.80	11,516	9,536	0.8280	1,980	0.00	1,980	56.5
1966	15,947.54	15,948	13,205	0.8280	2,742	0.00	2,742	55.5
1967	19,957.18	19,957	16,525	0.8280	3,432	0.00	3,432	54.5
1968	26,185.85	26,186	21,683	0.8280	4,503	0.00	4,503	53.5
1969	110,897.73	110,898	91,828	0.8280	19,070	0.00	19,070	52.5
1970	128,947.68	128,948	106,774	0.8280	22,174	0.00	22,174	51.5
1971	331,247.66	331,248	274,286	0.8280	56,962	0.00	56,962	50.5
1972	290,388.40	290,388	240,453	0.8280	49,936	0.00	49,936	49.5
1973	368,623.61	368,624	305,234	0.8280	63,389	0.00	63,389	48.5
1974	399,773.17	399,773	331,028	0.8280	68,746	0.00	68,746	47.5
1975	631,638.90	631,639	523,021	0.8280	108,618	0.00	108,618	46.5
1976	887,779.02	887,779	735,115	0.8280	152,664	0.00	152,664	45.5
1977	433,242.13	433,242	358,741	0.8280	74,501	0.00	74,501	44.5
1978	832,856.58	832,857	689,637	0.8280	143,219	0.00	143,219	43.5
1979	1,624,770.67	1,624,771	1,345,372	0.8280	279,398	0.00	279,398	42.5
1980	3,524,617.31	3,524,617	2,918,518	0.8280	606,099	0.00	606,099	41.5
1981	1,453,800.76	1,453,801	1,203,803	0.8280	249,998	0.00	249,998	40.5
1982	3,230,750.81	3,230,751	2,675,186	0.8280	555,565	0.00	555,565	39.5
1983	1,497,070.07	1,497,070	1,239,631	0.8280	257,439	0.00	257,439	38.5
1984	2,207,839.21	2,207,839	1,828,176	0.8280	379,664	0.00	379,664	37.5
1985	2,592,647.22	2,592,647	2,146,811	0.8280	445,836	0.00	445,836	36.5
1986	3,679,976.86	3,679,977	3,047,162	0.8280	632,815	0.00	632,815	35.5
1987	6,605,247.95	6,605,248	5,469,399	0.8280	1,135,849	0.00	1,135,849	34.5
1988	9,255,723.22	9,255,723	7,664,094	0.8280	1,591,629	0.00	1,591,629	33.5
1989	4,569,271.82	4,569,272	3,783,532	0.8280	785,739	0.00	785,739	32.5
1990	5,788,779.87	5,788,780	4,793,332	0.8280	995,448	0.00	995,448	31.5

Enbridge Gas Distribution

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	7,174,653.94	7,174,654	5,940,889	0.8280	1,233,765	0.00	1,233,765	30.5
1992	7,640,147.03	7,640,147	6,326,335	0.8280	1,313,812	0.00	1,313,812	29.5
1993	8,874,564.78	8,721,555	7,221,782	0.8138	1,652,783	0.50	1,652,783	28.5
1994	11,920,608.64	11,667,779	9,661,369	0.8105	2,259,240	0.60	2,259,240	27.5
1995	21,968,294.96	21,373,191	17,697,822	0.8056	4,270,473	0.74	4,270,473	26.5
1996	13,715,285.30	13,249,725	10,971,281	0.7999	2,744,005	0.90	2,744,005	25.5
1997	13,768,080.78	13,198,207	10,928,622	0.7938	2,839,459	1.06	2,684,146	24.5
1998	16,411,566.76	15,598,578	12,916,221	0.7870	3,495,346	1.22	2,853,794	23.5
1999	12,007,631.53	11,306,252	9,362,011	0.7797	2,645,621	1.40	1,895,444	22.5
2000	16,649,433.65	15,515,652	12,847,555	0.7717	3,801,878	1.57	2,419,917	21.5
2001	15,518,144.90	14,293,469	11,835,541	0.7627	3,682,604	1.76	2,096,610	20.5
2002	15,851,999.51	14,407,900	11,930,294	0.7526	3,921,705	1.95	2,006,522	19.5
2003	18,457,550.88	16,521,784	13,680,671	0.7412	4,776,880	2.17	2,203,821	18.5
2004	10,414,273.80	9,157,941	7,583,126	0.7281	2,831,147	2.40	1,179,282	17.5
2005	23,798,080.35	20,496,859	16,972,186	0.7132	6,825,895	2.66	2,568,552	16.5
2006	27,435,896.11	23,059,565	19,094,205	0.6960	8,341,692	2.94	2,835,720	15.5
2007	26,144,359.34	21,347,445	17,676,504	0.6761	8,467,856	3.26	2,598,899	14.5
2008	30,673,221.79	24,198,674	20,037,430	0.6533	10,635,792	3.61	2,944,545	13.5
2009	31,630,017.27	23,949,487	19,831,094	0.6270	11,798,923	4.01	2,943,319	12.5
2010	34,775,468.83	25,067,694	20,757,013	0.5969	14,018,456	4.45	3,147,727	11.5
2011	40,398,219.52	27,451,830	22,731,168	0.5627	17,667,051	4.95	3,567,774	10.5
2012	41,599,497.81	26,329,807	21,802,090	0.5241	19,797,408	5.51	3,593,372	9.5
2013	37,834,256.29	21,982,770	18,202,576	0.4811	19,631,680	6.13	3,202,956	8.5
2014	43,308,908.70	22,693,215	18,790,853	0.4339	24,518,056	6.81	3,598,511	7.5
2015	60,792,567.30	28,099,837	23,267,743	0.3827	37,524,824	7.56	4,962,013	6.5
2016	47,739,140.49	18,927,180	15,672,431	0.3283	32,066,709	8.37	3,830,053	5.5

Enbridge Gas Distribution

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	56,152,165.09	18,393,237	15,230,306	0.2712	40,921,859	9.24	4,429,772	4.5
2018	52,904,201.19	13,563,363	11,230,985	0.2123	41,673,216	10.15	4,104,996	3.5
2019	51,912,471.49	9,539,910	7,899,411	0.1522	44,013,060	11.10	3,963,703	2.5
2020	70,913,720.74	7,830,721	6,484,137	0.0914	64,429,583	12.08	5,331,918	1.5
2021	102,006,967.90	3,756,065	3,110,166	0.0305	98,896,802	13.08	7,561,514	0.5
TOTAL	1,020,910,893.69	567,033,992	469,525,898		551,384,996		104,686,374	

COMPOSITE ANNUAL ACCRUAL RATE	10.25%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.46
COMPOSITE AVERAGE AGE (YEARS)	11.32
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	6.37

Enbridge Gas Inc.

Account #: 482.00 - General Plant - Structures and Improvements - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1995	2,833,236.13	1,707,202	2,833,236	1.0000	0	17.48	0	26.5
1999	49,855.62	26,759	49,856	1.0000	0	19.42	0	22.5
2002	9,587.48	4,630	9,587	1.0000	0	20.88	0	19.5
2004	920.38	409	920	1.0000	0	21.84	0	17.5
2007	90,731.01	34,863	90,731	1.0000	0	23.24	0	14.5
2008	29,169.23	10,592	29,169	1.0000	0	23.68	0	13.5
2009	19,247.27	6,572	19,247	1.0000	0	24.11	0	12.5
2010	6,240.06	1,993	6,240	1.0000	0	24.52	0	11.5
2011	75,469.15	22,383	75,469	1.0000	0	24.90	0	10.5
2012	637,765.77	174,292	609,051	0.9550	28,715	25.26	1,137	9.5
2013	4,275,021.21	1,065,967	3,724,943	0.8713	550,078	25.59	21,497	8.5
2014	87,416.91	19,645	68,647	0.7853	18,770	25.87	725	7.5
2015	958,501.59	191,071	667,683	0.6966	290,818	26.11	11,139	6.5
2016	345,540.19	59,819	209,034	0.6049	136,506	26.27	5,196	5.5
2019	15,310.37	1,344	4,698	0.3068	10,612	25.97	409	2.5
2021	3,821,559.62	79,869	279,097	0.0730	3,542,463	23.42	151,233	0.5
TOTAL	13,255,571.99	3,407,411	8,677,610		4,577,962		191,336	

COMPOSITE ANNUAL ACCRUAL RATE	1.44%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.65
COMPOSITE AVERAGE AGE (YEARS)	9.98
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	23.22

Enbridge Gas Inc.

Account #: 482.01 - General Plant - Structures and Improvements - VPC
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2033

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1959	150,580.47	140,134	103,473	0.6872	47,107	4.66	10,111	62.5
1962	3,529,701.59	3,243,283	2,394,792	0.6785	1,134,910	5.25	215,987	59.5
1976	4,807,417.62	4,120,930	3,042,833	0.6329	1,764,584	7.58	232,806	45.5
1978	296.94	251	186	0.6252	111	7.87	14	43.5
1980	7,324.75	6,121	4,520	0.6171	2,805	8.16	344	41.5
1981	5,383.58	4,468	3,299	0.6128	2,084	8.30	251	40.5
1987	366,065.00	289,937	214,085	0.5848	151,980	9.06	16,777	34.5
1989	13,975.00	10,871	8,027	0.5744	5,948	9.28	641	32.5
2002	237,775.83	155,569	114,870	0.4831	122,906	10.30	11,928	19.5
2003	309,854.06	198,660	146,688	0.4734	163,166	10.35	15,758	18.5
2004	1,209,342.07	758,504	560,068	0.4631	649,274	10.40	62,420	17.5
2005	1,702,239.30	1,042,386	769,682	0.4522	932,557	10.44	89,284	16.5
2006	1,033,177.89	616,298	455,065	0.4405	578,113	10.48	55,139	15.5
2007	2,161,445.58	1,252,595	924,897	0.4279	1,236,548	10.52	117,533	14.5
2008	745,098.01	418,184	308,781	0.4144	436,317	10.55	41,343	13.5
2009	1,040,590.97	563,510	416,087	0.3999	624,504	10.58	59,011	12.5
2010	2,744,982.36	1,427,837	1,054,294	0.3841	1,690,689	10.61	159,372	11.5
2011	1,406,482.15	698,899	516,056	0.3669	890,426	10.63	83,762	10.5
2012	1,658,682.89	782,062	577,463	0.3481	1,081,220	10.65	101,536	9.5
2013	2,726,178.77	1,209,254	892,895	0.3275	1,833,284	10.66	171,935	8.5
2014	602,253.48	248,565	183,536	0.3047	418,717	10.67	39,235	7.5
2015	9,228,242.69	3,492,397	2,578,734	0.2794	6,649,509	10.68	622,877	6.5
2016	4,074,294.65	1,385,676	1,023,162	0.2511	3,051,132	10.67	285,911	5.5
2017	13,490,551.78	4,005,123	2,957,323	0.2192	10,533,229	10.66	988,343	4.5
2018	3,622.63	897	663	0.1829	2,960	10.63	279	3.5
2020	207,794.29	26,070	19,250	0.0926	188,544	10.46	18,032	1.5

Enbridge Gas Inc.

Account #: 482.01 - General Plant - Structures and Improvements - VPC

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2033

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	53,463,354.35	26,098,479	19,270,729		34,192,626		3,400,629	

COMPOSITE ANNUAL ACCRUAL RATE	6.36%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.36
COMPOSITE AVERAGE AGE (YEARS)	15.24
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	9.97

Enbridge Gas Inc.

Account #: 482.04 - General Plant - Structures and Improvements - Thorold
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2022

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2002	73,458.65	71,622	31,416	0.4277	42,043	0.50	42,043	19.5
2003	155,088.99	151,008	66,237	0.4271	88,852	0.50	88,852	18.5
2004	543,366.08	528,273	231,718	0.4264	311,649	0.50	311,649	17.5
2005	85,913.98	83,387	36,576	0.4257	49,338	0.50	49,338	16.5
2006	224,274.90	217,266	95,300	0.4249	128,975	0.50	128,975	15.5
2007	533,394.60	515,615	226,165	0.4240	307,229	0.50	307,229	14.5
2008	187,214.72	180,528	79,186	0.4230	108,029	0.50	108,029	13.5
2009	151,221.70	145,405	63,780	0.4218	87,442	0.50	87,442	12.5
2010	179,072.00	171,611	75,274	0.4204	103,798	0.50	103,798	11.5
2011	752,683.51	718,471	315,145	0.4187	437,539	0.50	437,539	10.5
2012	275,143.36	261,386	114,652	0.4167	160,491	0.50	160,491	9.5
2013	1,628,079.52	1,537,631	674,455	0.4143	953,625	0.50	953,625	8.5
2014	483,576.03	453,353	198,855	0.4112	284,721	0.50	284,721	7.5
2015	618,715.01	574,521	252,004	0.4073	366,711	0.50	366,711	6.5
2016	9,224,708.22	8,455,983	3,709,069	0.4021	5,515,640	0.50	5,515,640	5.5
2017	562,728.71	506,456	222,148	0.3948	340,581	0.50	340,581	4.5
TOTAL	15,678,639.98	14,572,515	6,391,978		9,286,662		9,286,662	

COMPOSITE ANNUAL ACCRUAL RATE	59.23%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.41
COMPOSITE AVERAGE AGE (YEARS)	7.54
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	0.50

Enbridge Gas Distribution

Account #: 482.05 - General Plant - Structures and Improvements - Markham

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2046

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2011	147,807.89	52,250	31,358	0.2122	116,450	19.20	6,064	10.5
2012	31,727,969.48	10,465,736	6,281,077	0.1980	25,446,892	19.30	1,318,475	9.5
2013	480,360.14	146,466	87,902	0.1830	392,458	19.38	20,254	8.5
2014	28,044.58	7,810	4,687	0.1671	23,357	19.43	1,202	7.5
2015	350,547.36	87,779	52,681	0.1503	297,866	19.46	15,308	6.5
2016	53,237.11	11,736	7,043	0.1323	46,194	19.45	2,375	5.5
2017	2,424,985.17	456,656	274,065	0.1130	2,150,921	19.40	110,893	4.5
2018	557,163.34	85,617	51,384	0.0922	505,780	19.28	26,238	3.5
2019	901,703.23	104,609	62,782	0.0696	838,922	19.05	44,039	2.5
TOTAL	36,671,818.30	11,418,658	6,852,980		29,818,839		1,544,848	

COMPOSITE ANNUAL ACCRUAL RATE	4.21%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.19
COMPOSITE AVERAGE AGE (YEARS)	8.86
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	19.30

Enbridge Gas Inc.

Account #: 482.51 - General Plant - Structures and Improvements - Keil Head Office
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2049

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1967	13,561,856.85	12,047,160	5,330,016	0.3930	8,231,841	6.85	1,201,322	54.5
1975	446.57	373	165	0.3692	282	9.22	31	46.5
1979	6,216,146.70	4,979,943	2,203,272	0.3544	4,012,874	10.55	380,365	42.5
1981	13,941.98	10,911	4,827	0.3463	9,115	11.25	810	40.5
1985	66,514.62	49,346	21,832	0.3282	44,683	12.70	3,518	36.5
1997	379,854.39	224,020	99,113	0.2609	280,742	17.04	16,473	24.5
2000	1,277,664.70	695,333	307,635	0.2408	970,029	18.01	53,873	21.5
2001	21,783.20	11,507	5,091	0.2337	16,692	18.31	912	20.5
2002	319,247.25	163,411	72,298	0.2265	246,950	18.60	13,280	19.5
2003	177,371.10	87,800	38,845	0.2190	138,526	18.87	7,340	18.5
2004	345,763.11	165,155	73,069	0.2113	272,694	19.14	14,249	17.5
2005	2,288,214.33	1,052,042	465,454	0.2034	1,822,760	19.39	94,015	16.5
2006	615,728.02	271,720	120,217	0.1952	495,511	19.62	25,251	15.5
2007	3,758,480.63	1,586,827	702,059	0.1868	3,056,422	19.84	154,023	14.5
2008	738,700.30	297,260	131,516	0.1780	607,184	20.05	30,287	13.5
2009	50,411.58	19,250	8,517	0.1689	41,895	20.23	2,070	12.5
2010	230,329.13	83,028	36,734	0.1595	193,595	20.40	9,489	11.5
2011	537,306.10	181,697	80,388	0.1496	456,918	20.55	22,234	10.5
2012	3,754,845.50	1,182,099	522,995	0.1393	3,231,851	20.68	156,309	9.5
2013	120,106.76	34,870	15,427	0.1284	104,679	20.78	5,038	8.5
2014	756,715.04	200,178	88,565	0.1170	668,150	20.85	32,043	7.5
2015	45,824.26	10,874	4,811	0.1050	41,013	20.89	1,963	6.5
2016	790,984.23	164,841	72,930	0.0922	718,054	20.89	34,370	5.5
2017	561,981.30	99,815	44,161	0.0786	517,820	20.84	24,852	4.5
2018	11,296,540.09	1,633,672	722,784	0.0640	10,573,756	20.70	510,764	3.5
2019	4,408,233.57	480,391	212,539	0.0482	4,195,695	20.44	205,260	2.5

Enbridge Gas Inc.

Account #: 482.51 - General Plant - Structures and Improvements - Keil Head Office

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2049

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2020	344,597.48	24,114	10,669	0.0310	333,929	19.94	16,750	1.5
2021	16,879,086.37	438,510	194,010	0.0115	16,685,077	18.75	890,063	0.5
TOTAL	69,558,675.16	26,196,143	11,589,939		57,968,736		3,906,954	

COMPOSITE ANNUAL ACCRUAL RATE	5.62%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.17
COMPOSITE AVERAGE AGE (YEARS)	18.53
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	16.39

Enbridge Gas Inc.

Account #: 482.52 - General Plant - Structures and Improvements - Bloomfield Training Center
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2028

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1993	2,769,967.65	2,289,629	359,174	0.1297	2,410,794	5.98	403,212	28.5
2006	77,583.70	55,349	8,683	0.1119	68,901	6.23	11,065	15.5
2010	3,572.99	2,313	363	0.1016	3,210	6.26	512	11.5
2015	15,770,377.95	8,015,945	1,257,460	0.0797	14,512,918	6.29	2,308,055	6.5
2016	7,325.00	3,418	536	0.0732	6,789	6.29	1,080	5.5
2017	571,743.83	238,537	37,419	0.0654	534,325	6.29	85,003	4.5
2020	37,121.15	7,200	1,129	0.0304	35,992	6.23	5,774	1.5
TOTAL	19,237,692.27	10,612,391	1,664,764		17,572,928		2,814,701	

COMPOSITE ANNUAL ACCRUAL RATE	14.63%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.09
COMPOSITE AVERAGE AGE (YEARS)	9.64
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	6.24

Enbridge Gas Distribution

Account #: 483.00 - General Plant - Office Furniture and Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	1,547,876.38	1,496,281	1,547,876	1.0000	0	0.50	0	14.5
2008	1,553,124.29	1,397,812	1,553,124	1.0000	0	1.50	0	13.5
2009	900,993.44	750,828	900,993	1.0000	0	2.50	0	12.5
2010	2,986,237.93	2,289,449	2,986,238	1.0000	0	3.50	0	11.5
2011	5,308,576.65	3,716,004	5,148,386	0.9698	160,190	4.50	35,598	10.5
2012	3,368,001.99	2,133,068	2,133,068	0.6333	1,234,934	5.50	224,533	9.5
2013	2,710,535.67	1,535,970	1,535,970	0.5667	1,174,565	6.50	180,702	8.5
2014	1,505,699.50	752,850	752,850	0.5000	752,850	7.50	100,380	7.5
2015	5,464,200.44	2,367,820	2,367,820	0.4333	3,096,380	8.50	364,280	6.5
2016	2,741,359.73	1,005,165	1,005,165	0.3667	1,736,195	9.50	182,757	5.5
2017	897,281.50	269,184	269,184	0.3000	628,097	10.50	59,819	4.5
2018	245,022.65	57,172	57,172	0.2333	187,851	11.50	16,335	3.5
2019	259,637.87	43,273	43,273	0.1667	216,365	12.50	17,309	2.5
2020	190,363.95	19,036	19,036	0.1000	171,328	13.50	12,691	1.5
2021	97,149.73	3,238	3,238	0.0333	93,911	14.50	6,477	0.5
TOTAL	29,776,061.72	17,837,150	20,323,396		9,452,666		1,200,881	

COMPOSITE ANNUAL ACCRUAL RATE	4.03%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.68
COMPOSITE AVERAGE AGE (YEARS)	8.99
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	6.01

Enbridge Gas Distribution

Account #: 484.00 - General Plant - Transportation Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L2.5
ASL: 12
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1995	5,886.93	5,586	5,887	1.0000	0	1.43	0	26.5
1996	83,994.02	79,244	83,994	1.0000	0	1.53	0	25.5
1997	52,226.12	48,954	52,226	1.0000	0	1.64	0	24.5
1998	50,541.63	47,030	50,542	1.0000	0	1.75	0	23.5
1999	86,150.36	79,496	86,150	1.0000	0	1.88	0	22.5
2000	18,051.76	16,498	18,052	1.0000	0	2.03	0	21.5
2001	42,775.16	38,665	42,775	1.0000	0	2.18	0	20.5
2002	229,028.25	204,437	229,028	1.0000	0	2.35	0	19.5
2003	16,122.29	14,187	16,122	1.0000	0	2.52	0	18.5
2004	66,451.06	57,544	66,451	1.0000	0	2.71	0	17.5
2005	836,851.01	711,832	836,851	1.0000	0	2.90	0	16.5
2006	1,377,310.68	1,148,806	1,377,311	1.0000	0	3.08	0	15.5
2007	2,855,091.60	2,332,028	2,855,092	1.0000	0	3.25	0	14.5
2008	6,726,949.02	5,375,289	6,726,949	1.0000	0	3.39	0	13.5
2009	3,296,003.61	2,573,632	3,296,004	1.0000	0	3.51	0	12.5
2010	4,821,371.64	3,669,887	4,821,372	1.0000	0	3.61	0	11.5
2011	10,705,900.73	7,902,079	10,705,901	1.0000	0	3.73	0	10.5
2012	4,796,858.36	3,401,124	4,715,327	0.9830	81,531	3.90	20,913	9.5
2013	9,324,424.44	6,260,667	8,679,805	0.9309	644,619	4.16	154,971	8.5
2014	13,104,260.47	8,171,056	11,328,373	0.8645	1,775,888	4.53	392,196	7.5
2015	13,077,169.99	7,387,071	10,241,455	0.7832	2,835,715	5.01	566,372	6.5
2016	4,897,079.13	2,429,250	3,367,918	0.6877	1,529,161	5.59	273,683	5.5
2017	11,632,470.15	4,866,831	6,747,387	0.5800	4,885,083	6.26	780,903	4.5
2018	9,886,113.84	3,299,250	4,574,089	0.4627	5,312,025	6.99	760,201	3.5
2019	17,270,979.10	4,205,624	5,830,689	0.3376	11,440,290	7.77	1,473,012	2.5
2020	10,417,592.94	1,546,342	2,143,852	0.2058	8,273,741	8.61	961,460	1.5

Enbridge Gas Distribution

Account #: 484.00 - General Plant - Transportation Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L2.5
ASL: 12
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2021	9,044,423.40	451,693	626,228	0.0692	8,418,195	9.51	885,036	0.5
TOTAL	134,722,077.69	66,324,101	89,525,829		45,196,249		6,268,747	

COMPOSITE ANNUAL ACCRUAL RATE	4.65%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.66
COMPOSITE AVERAGE AGE (YEARS)	6.50
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	5.72

Enbridge Gas Distribution

Account #: 485.00 - General Plant - Heavy Work Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L1.5
ASL: 17
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	24,477.11	21,807	14,551	0.5945	9,926	3.73	2,658	30.5
1996	57,293.11	48,475	32,345	0.5646	24,948	4.64	5,378	25.5
1997	153,581.23	128,305	85,612	0.5574	67,970	4.83	14,082	24.5
1998	566,336.21	466,731	311,427	0.5499	254,909	5.02	50,828	23.5
1999	5,501.12	4,468	2,981	0.5419	2,520	5.20	484	22.5
2000	44,256.52	35,387	23,612	0.5335	20,645	5.39	3,831	21.5
2001	225,036.23	176,948	118,069	0.5247	106,967	5.57	19,200	20.5
2002	170,705.94	131,841	87,971	0.5153	82,735	5.75	14,393	19.5
2003	530,446.58	401,862	268,143	0.5055	262,303	5.92	44,312	18.5
2004	1,297,998.39	963,129	642,649	0.4951	655,349	6.08	107,707	17.5
2005	785,151.61	569,591	380,060	0.4841	405,091	6.24	64,873	16.5
2006	1,365,513.31	966,404	644,834	0.4722	720,679	6.40	112,584	15.5
2007	1,132,626.49	779,867	520,367	0.4594	612,259	6.56	93,349	14.5
2008	2,495,276.47	1,665,817	1,111,519	0.4454	1,383,757	6.72	205,854	13.5
2009	1,772,253.56	1,142,093	762,063	0.4300	1,010,191	6.90	146,468	12.5
2010	6,975,444.40	4,314,967	2,879,168	0.4128	4,096,276	7.09	577,709	11.5
2011	2,345,474.49	1,382,809	922,682	0.3934	1,422,793	7.31	194,643	10.5
2012	1,136,773.17	632,965	422,347	0.3715	714,426	7.56	94,482	9.5
2013	1,744,541.95	906,566	604,907	0.3467	1,139,635	7.86	145,049	8.5
2014	2,014,513.49	961,949	641,862	0.3186	1,372,652	8.21	167,264	7.5
2015	2,059,334.05	885,781	591,039	0.2870	1,468,295	8.61	170,500	6.5
2016	165,150.70	62,374	41,619	0.2520	123,531	9.06	13,631	5.5
2017	1,082,169.54	346,739	231,362	0.2138	850,808	9.54	89,141	4.5
2018	3,490,404.68	901,088	601,253	0.1723	2,889,152	10.06	287,266	3.5
2019	1,977,122.87	377,225	251,704	0.1273	1,725,419	10.60	162,728	2.5
2020	6,382,757.51	755,573	504,157	0.0790	5,878,600	11.17	526,220	1.5

Enbridge Gas Distribution

Account #: 485.00 - General Plant - Heavy Work Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L1.5
ASL: 17
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2021	4,128,780.23	169,293	112,961	0.0274	4,015,819	11.69	343,403	0.5
TOTAL	44,128,920.96	19,200,053	12,811,266		31,317,655		3,658,038	

COMPOSITE ANNUAL ACCRUAL RATE	8.29%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	8.17
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	8.57

Enbridge Gas Distribution

Account #: 486.00 - General Plant - Tools and Work Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2000	0.00	0	0	0.0000	0	0.00	0	21.5
2001	0.00	0	0	0.0000	0	0.00	0	20.5
2007	3,961,806.89	3,829,747	2,526,117	0.6376	1,435,690	0.50	1,435,690	14.5
2008	5,913,146.36	5,321,832	3,510,303	0.5936	2,402,844	1.50	1,601,896	13.5
2009	2,354,607.71	1,962,173	1,294,258	0.5497	1,060,350	2.50	424,140	12.5
2010	5,781,919.10	4,432,805	2,923,897	0.5057	2,858,022	3.50	816,578	11.5
2011	3,577,126.15	2,503,988	1,651,641	0.4617	1,925,485	4.50	427,886	10.5
2012	3,663,115.28	2,319,973	1,530,264	0.4177	2,132,851	5.50	387,791	9.5
2013	4,095,836.08	2,320,974	1,530,924	0.3738	2,564,912	6.50	394,602	8.5
2014	16,180,032.47	8,090,016	5,336,209	0.3298	10,843,824	7.50	1,445,843	7.5
2015	6,286,115.38	2,723,983	1,796,751	0.2858	4,489,364	8.50	528,161	6.5
2016	4,352,180.39	1,595,799	1,052,596	0.2419	3,299,584	9.50	347,325	5.5
2017	5,806,688.57	1,742,007	1,149,035	0.1979	4,657,654	10.50	443,586	4.5
2018	3,840,750.35	896,175	591,121	0.1539	3,249,629	11.50	282,576	3.5
2019	8,667,286.86	1,444,548	952,830	0.1099	7,714,457	12.50	617,157	2.5
2020	3,675,931.58	367,593	242,466	0.0660	3,433,466	13.50	254,331	1.5
2021	1,810,311.19	60,344	39,803	0.0220	1,770,508	14.50	122,104	0.5
TOTAL	79,966,854.36	39,611,957	26,128,214		53,838,641		9,529,664	

COMPOSITE ANNUAL ACCRUAL RATE 11.92%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.33

COMPOSITE AVERAGE AGE (YEARS) 7.43

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 7.57

Enbridge Gas Distribution

Account #: 487.70 - General Plant - Rental - Refuel Appliances

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2010	6,325.54	4,850	1,359	0.2149	4,966	3.50	1,419	11.5
2011	15,903.43	11,132	3,120	0.1962	12,783	4.50	2,841	10.5
2012	55,313.16	35,032	9,818	0.1775	45,495	5.50	8,272	9.5
2014	14,464.61	7,232	2,027	0.1401	12,438	7.50	1,658	7.5
2015	328,514.61	142,356	39,899	0.1215	288,616	8.50	33,955	6.5
2016	234,947.75	86,148	24,145	0.1028	210,803	9.50	22,190	5.5
2018	169,405.73	39,528	11,079	0.0654	158,327	11.50	13,768	3.5
2020	18,405.86	1,841	516	0.0280	17,890	13.50	1,325	1.5
2021	21,473.92	716	201	0.0093	21,273	14.50	1,467	0.5
TOTAL	864,754.61	328,834	92,164		772,591		86,894	

COMPOSITE ANNUAL ACCRUAL RATE	10.05%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.11
COMPOSITE AVERAGE AGE (YEARS)	5.70
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	9.30

Enbridge Gas Distribution

Account #: 487.80 - General Plant - Rental - NGV Stations

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	13,855.60	3,118	13,856	1.0000	0	15.50	0	4.5
2019	2,212,175.03	276,522	2,022,160	0.9141	190,015	17.50	10,858	2.5
2020	4,448,475.41	333,636	333,636	0.0750	4,114,840	18.50	222,424	1.5
2021	1,099,668.82	27,492	27,492	0.0250	1,072,177	19.50	54,983	0.5
TOTAL	7,774,174.86	640,767	2,397,143		5,377,032		288,265	

COMPOSITE ANNUAL ACCRUAL RATE	3.71%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	1.65
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	18.35

Enbridge Gas Distribution

Account #: 488.00 - General Plant - Communication Structures and Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	307,126.40	307,126	184,237	0.5999	122,890	0.00	122,890	14.5
2008	128,223.13	128,223	76,918	0.5999	51,306	0.00	51,306	13.5
2010	1,561,084.54	1,561,085	936,452	0.5999	624,632	0.00	624,632	11.5
2011	809,669.52	809,670	485,699	0.5999	323,971	0.00	323,971	10.5
2012	1,185,159.94	1,125,902	675,398	0.5699	509,762	0.50	509,762	9.5
2013	522,285.32	443,943	266,309	0.5099	255,976	1.50	170,651	8.5
2014	2,082,386.97	1,561,790	936,876	0.4499	1,145,511	2.50	458,205	7.5
2015	1,489,428.62	968,129	580,754	0.3899	908,675	3.50	259,621	6.5
2016	1,250,210.87	687,616	412,482	0.3299	837,729	4.50	186,162	5.5
2017	1,361,551.69	612,698	367,541	0.2699	994,011	5.50	180,729	4.5
2018	26,564.77	9,298	5,577	0.2100	20,987	6.50	3,229	3.5
2019	317,207.03	79,302	47,571	0.1500	269,636	7.50	35,951	2.5
2020	153,462.71	23,019	13,809	0.0900	139,654	8.50	16,430	1.5
2021	30,247.69	1,512	907	0.0300	29,340	9.50	3,088	0.5
TOTAL	11,224,609.20	8,319,312	4,990,530		6,234,079		2,946,627	

COMPOSITE ANNUAL ACCRUAL RATE	26.25%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.44
COMPOSITE AVERAGE AGE (YEARS)	7.82
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	2.59

Enbridge Gas Distribution

Account #: 490.00 - General Plant - Computer Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 4
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2018	6,964,752.60	6,094,159	6,964,753	1.0000	0	0.50	0	3.5
2019	11,281,679.70	7,051,050	9,742,129	0.8635	1,539,551	1.50	1,026,367	2.5
2020	10,240,619.70	3,840,232	3,840,232	0.3750	6,400,387	2.50	2,560,155	1.5
2021	1,819,626.69	227,453	227,453	0.1250	1,592,173	3.50	454,907	0.5
TOTAL	30,306,678.69	17,212,894	20,774,567		9,532,112		4,041,429	

COMPOSITE ANNUAL ACCRUAL RATE	13.34%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	2.27
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	1.73

Enbridge Gas Inc.

Account #: 490.30 - General Plant - Computer Equipment - WAMS
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2016	4,680,899.13	2,574,495	2,418,465	0.5167	2,262,435	4.50	502,763	5.5
TOTAL	4,680,899.13	2,574,495	2,418,465		2,262,435		502,763	

COMPOSITE ANNUAL ACCRUAL RATE	10.74%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	5.50
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	4.50

Enbridge Gas Distribution

Account #: 491.01 - Software - Acquired Intangibles

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 4
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	5,933,217.48	5,933,217	5,933,217	1.0000	0	0.00	0	4.5
2018	24,321,547.69	21,281,354	24,321,548	1.0000	0	0.50	0	3.5
2019	64,148,946.33	40,093,091	64,148,946	1.0000	0	1.50	0	2.5
2020	5,286,014.31	1,982,255	5,286,014	1.0000	0	2.50	0	1.5
2021	55,475,059.58	6,934,382	7,860,612	0.1417	47,614,448	3.50	13,604,128	0.5
TOTAL	155,164,785.39	76,224,301	107,550,337		47,614,448		13,604,128	

COMPOSITE ANNUAL ACCRUAL RATE	8.77%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	1.98
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	2.04

Enbridge Gas Distribution

Account #: 491.02 - Software - Developed Intangibles

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 4
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2018	9,486,577.80	8,300,756	9,486,578	1.0000	0	0.50	0	3.5
2019	5,619,946.21	3,512,466	5,619,946	1.0000	0	1.50	0	2.5
2020	9,566,744.92	3,587,529	8,649,956	0.9042	916,789	2.50	366,716	1.5
2021	14,103,018.70	1,762,877	1,762,877	0.1250	12,340,141	3.50	3,525,755	0.5
TOTAL	38,776,287.63	17,163,629	25,519,357		13,256,930		3,892,470	

COMPOSITE ANNUAL ACCRUAL RATE	10.04%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.66
COMPOSITE AVERAGE AGE (YEARS)	1.77
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	2.23

Enbridge Gas Distribution

Account #: 491.03 - Software - CIS Acquired

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2015	13,559,337.94	8,813,570	13,559,338	1.0000	0	3.50	0	6.5
2020	13,812,372.94	2,071,856	3,678,108	0.2663	10,134,265	8.50	1,192,266	1.5
2021	60,254,502.69	3,012,725	3,012,725	0.0500	57,241,778	9.50	6,025,450	0.5
TOTAL	87,626,213.57	13,898,151	20,250,171		67,376,042		7,217,717	

COMPOSITE ANNUAL ACCRUAL RATE	8.24%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	1.59
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	8.41

Enbridge Gas Distribution

Account #: 491.04 - Software - WAMS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2016	85,221,905.36	46,872,048	44,031,318	0.5167	41,190,587	4.50	9,153,464	5.5
TOTAL	85,221,905.36	46,872,048	44,031,318		41,190,587		9,153,464	

COMPOSITE ANNUAL ACCRUAL RATE	10.74%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	5.50
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	4.50

9 ESTIMATION OF SURVIVOR CURVES

9.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service"[4]. All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

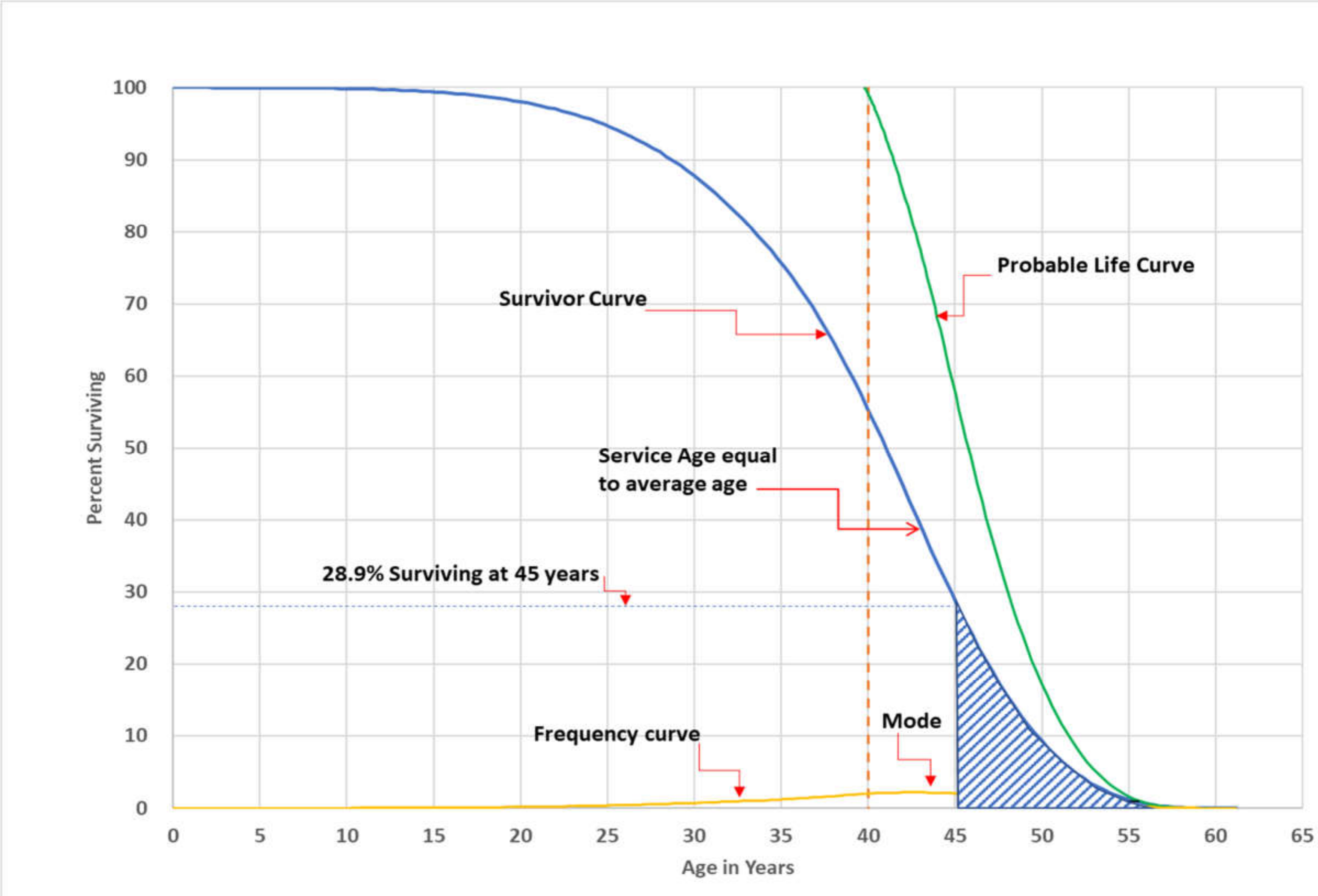
9.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age"[5]. To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1 shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age."[6] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve[7]. Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

[4] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21.
[5] *Ibid*, 23.
[6] *Ibid*, 29.
[7] *Ibid*, 23-24.

FIGURE 1: TYPICAL SURVIVOR CURVE (40-R4) AND DERIVED CURVES



9.3 Iowa Type Curves

In 1931, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment"[8]. The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves are presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation[9]. In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[10] presenting his development of the fourth family consisting of the four O-type survivor curves.

[8] *Ibid*, 21

[9] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[10] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957)

FIGURE 2: LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

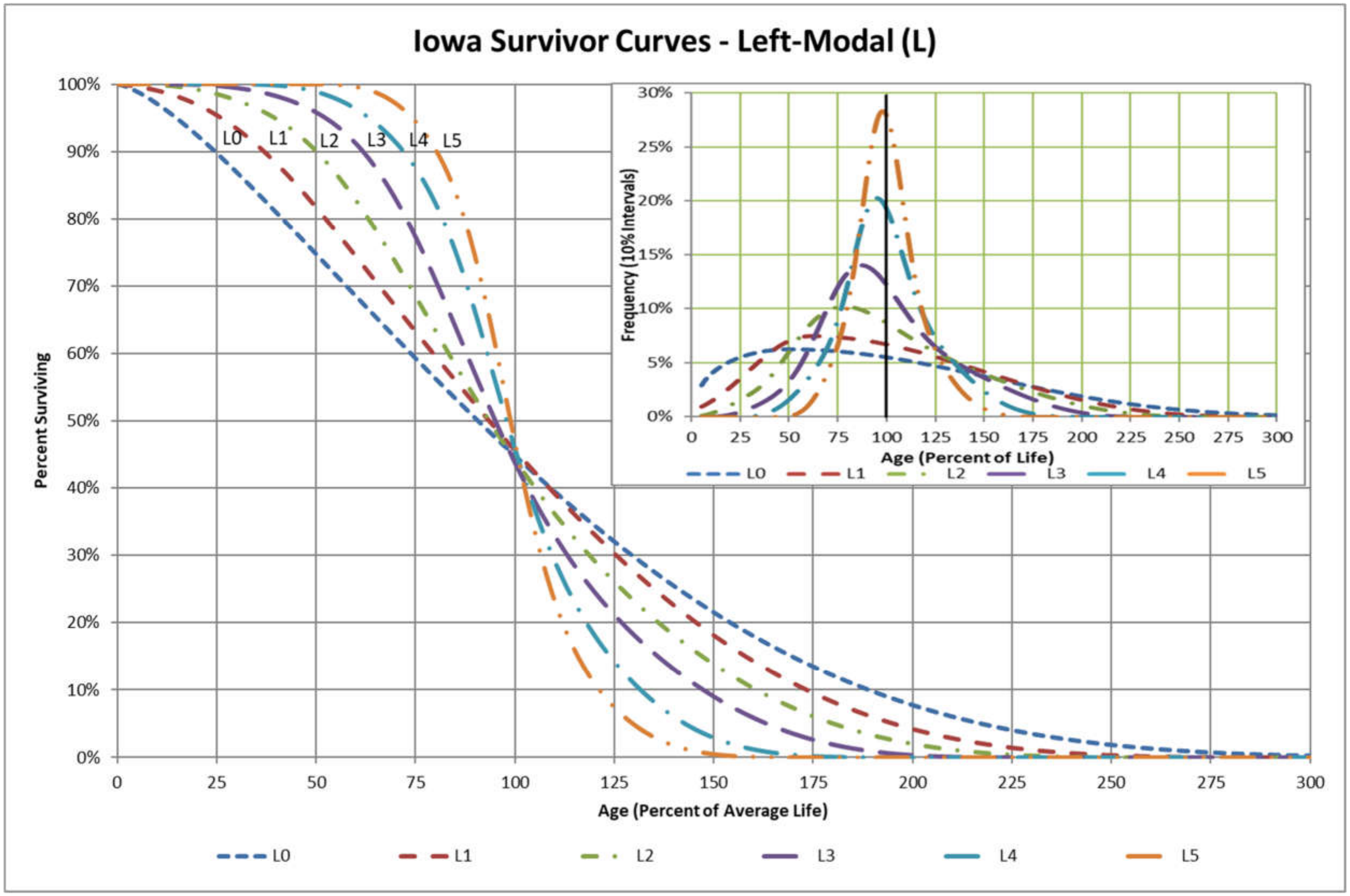


FIGURE 3: RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

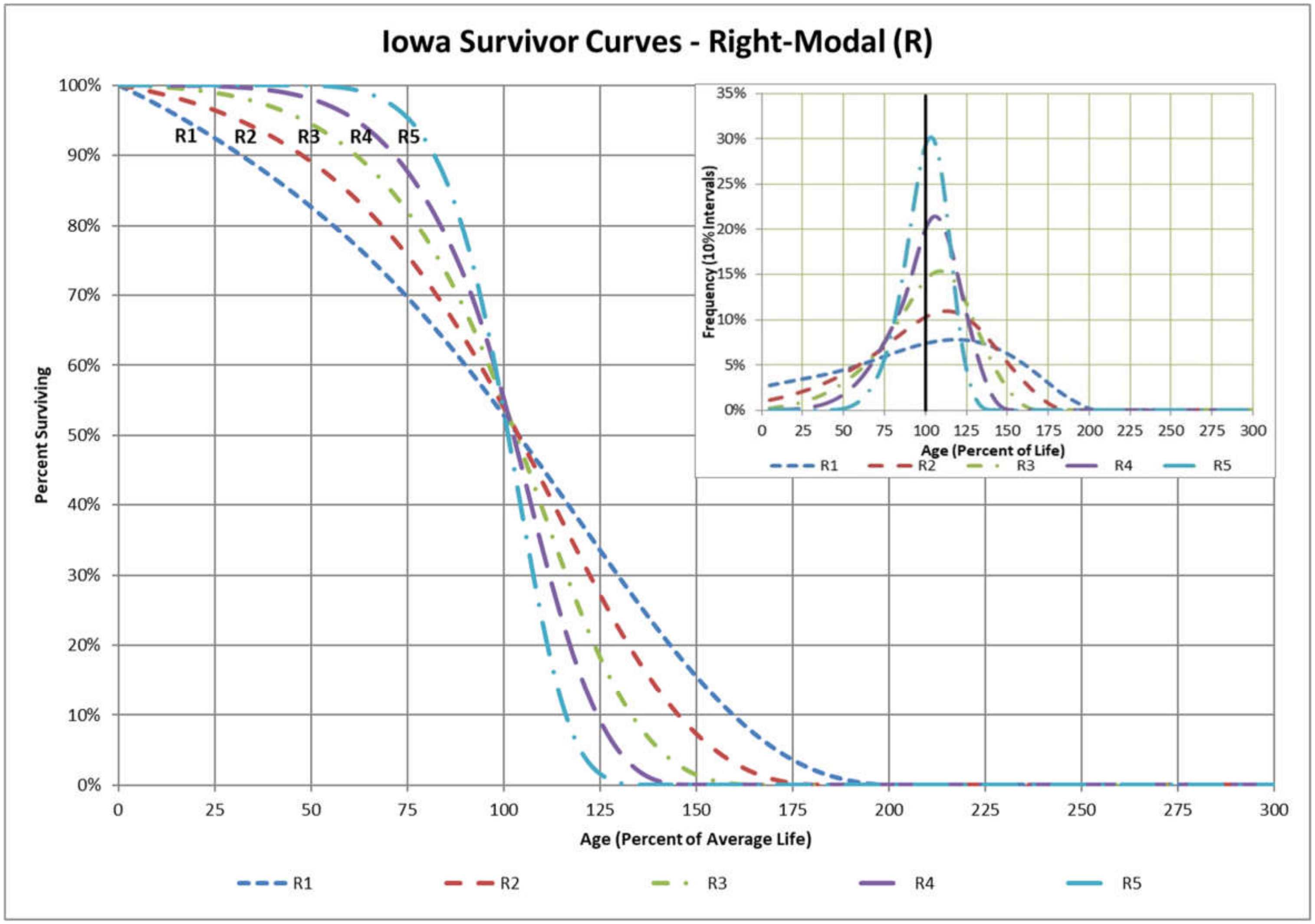


FIGURE 4: SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

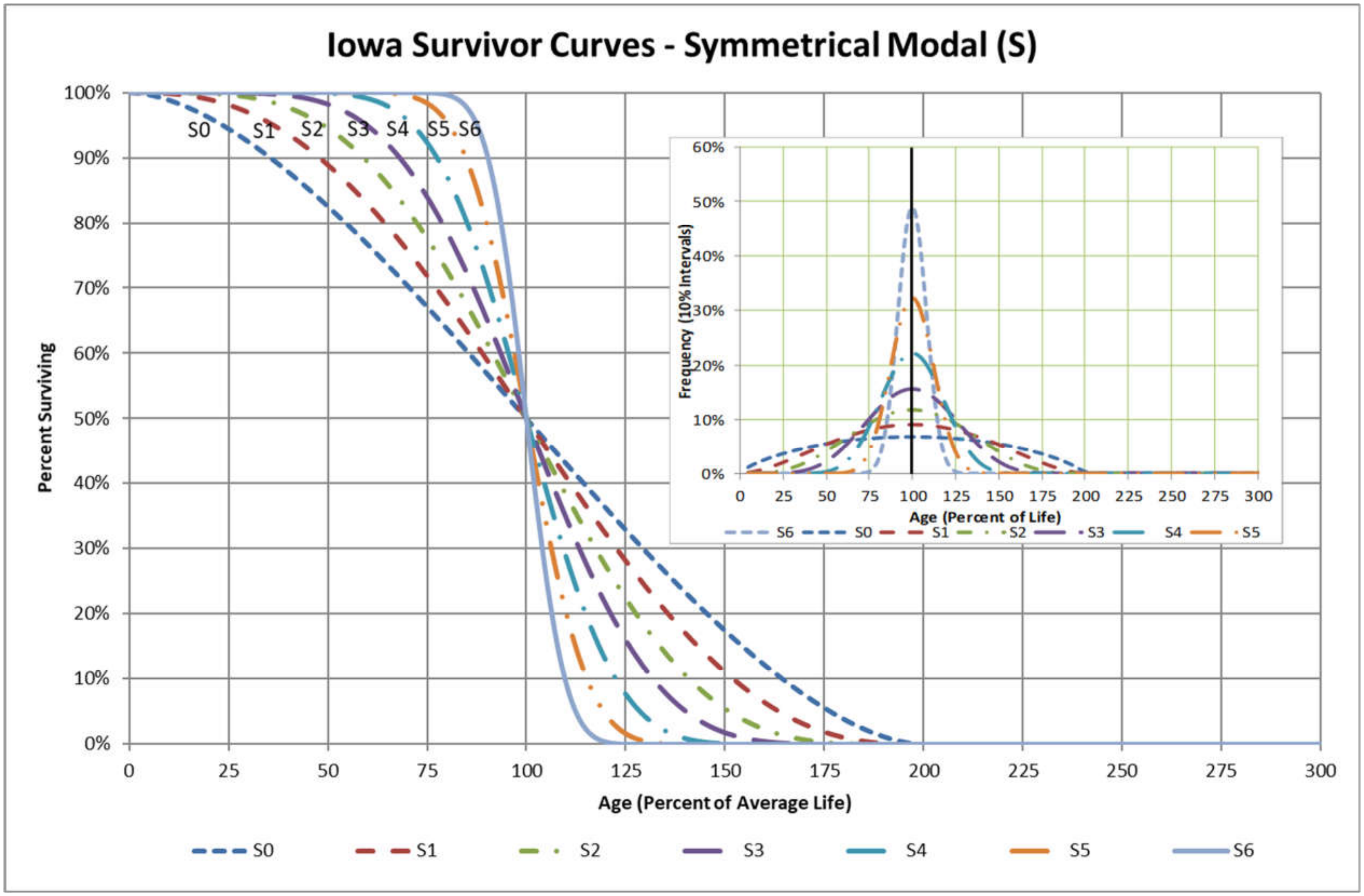
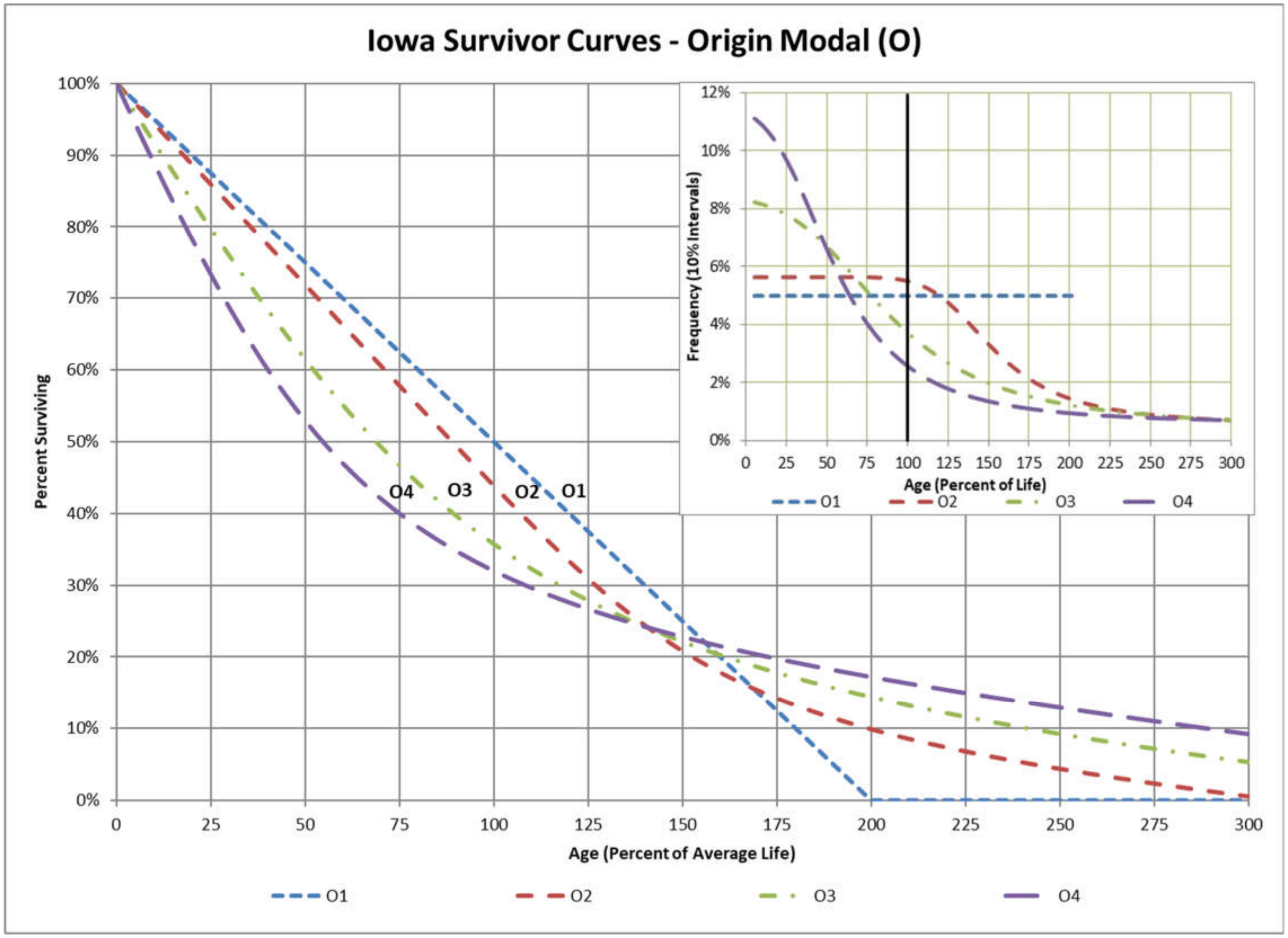


FIGURE 5: ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES



9.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements,[11] Engineering Valuation and Depreciation[12] and Depreciation Systems[13].

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

9.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-10), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

[11] Anson, Winfrey & Hempstead, supra note 7
[12] Anson, Winfrey & Hempstead, supra note 7
[13] Wolf & Fitch, supra note 2

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-11). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 Placement Band 2003-2017

Retrements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] *Transfer Affecting Exposures at Beginning of Year*
[b] *Transfer Affecting Exposures at End of Year*
[c] *Sale with Continued Use*
Parentheses denote Credit amount.

9.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-13). The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	$750,000
Exposures at age ½	=	$750,000 - $ 8,000	=	$742,000
Exposures at age 1½	=	$742,000 - $18,000	=	$724,000
Exposures at age 2½	=	$724,000 - $20,000 - $19,000	=	$685,000
Exposures at age 3½	=	$685,000 - $22,000	=	$663,000

For the entire experience band 2008-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$255 + $268 + $ 284 + $311 + $334 + $374 + $405 + $448 + $501 $ $609 = $3,789k

SCHEDULE 3 – PLANT EXPOSED TO RETIREMENT AT THE BEGINNING OF EACH YEAR, 2008 -2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008 - 2017

Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
420	460	510	580	660	750	850	960	1080	1220	0
1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

9.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 9-15) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	$3,789,000		
Retirements from age 4½ to 5½	=	$143,000		
Retirement Ratio	=	$143,000 ÷ $3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

SCHEDULE 4: ORIGINAL LIFE TABLE - CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017					Placement Band 2003-2017
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

9.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

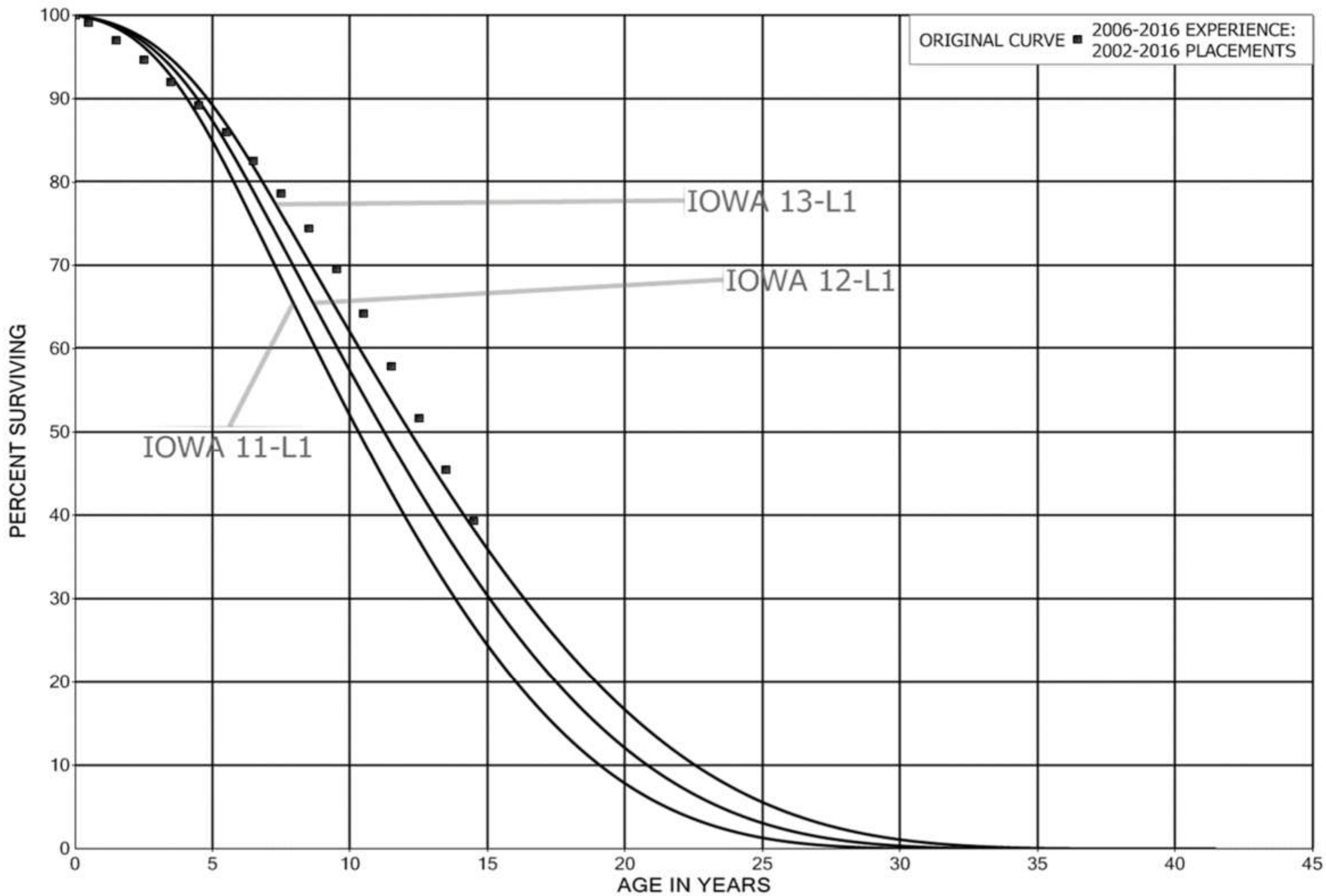


FIGURE 7: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A SO IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

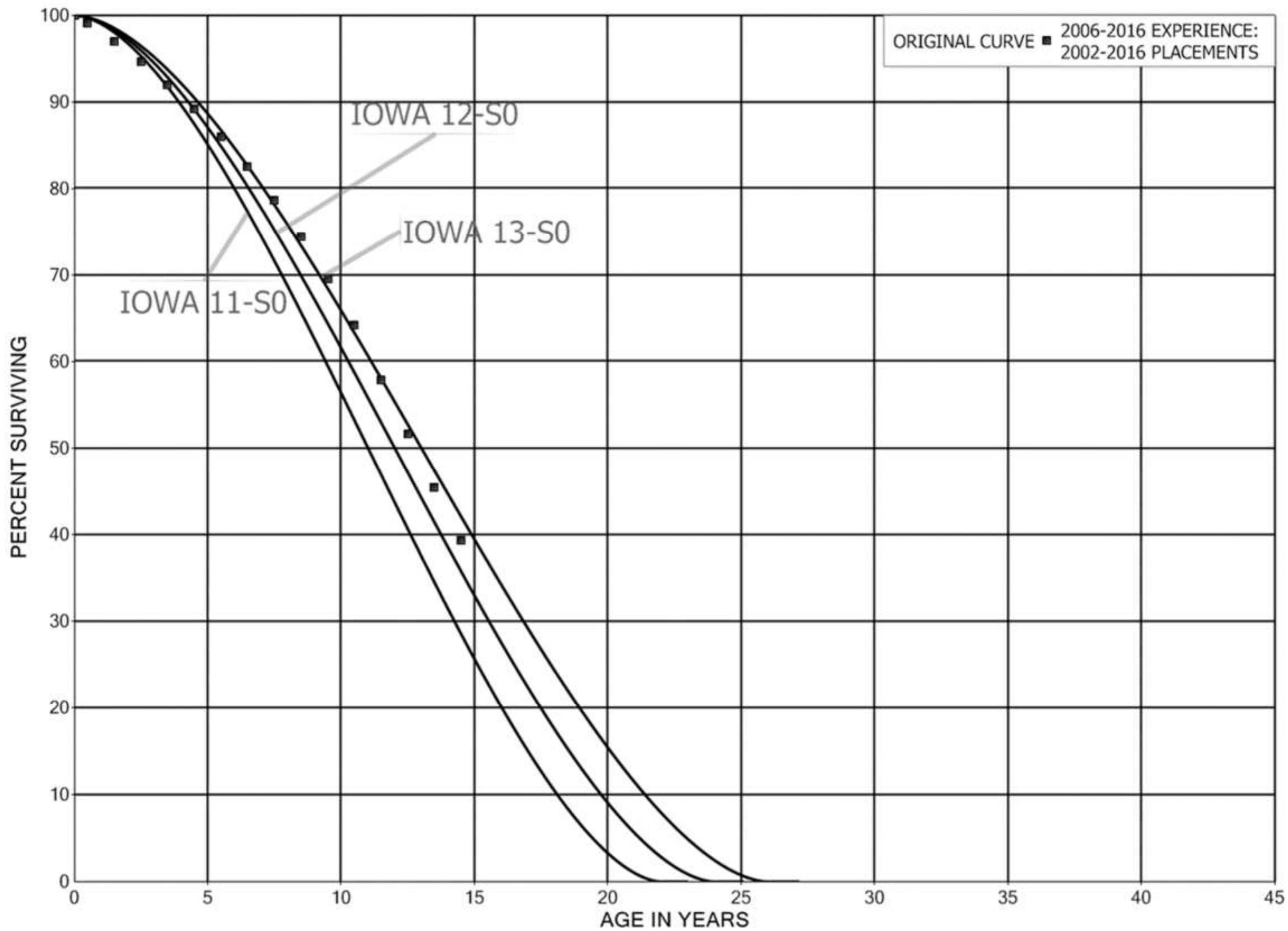


FIGURE 8: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

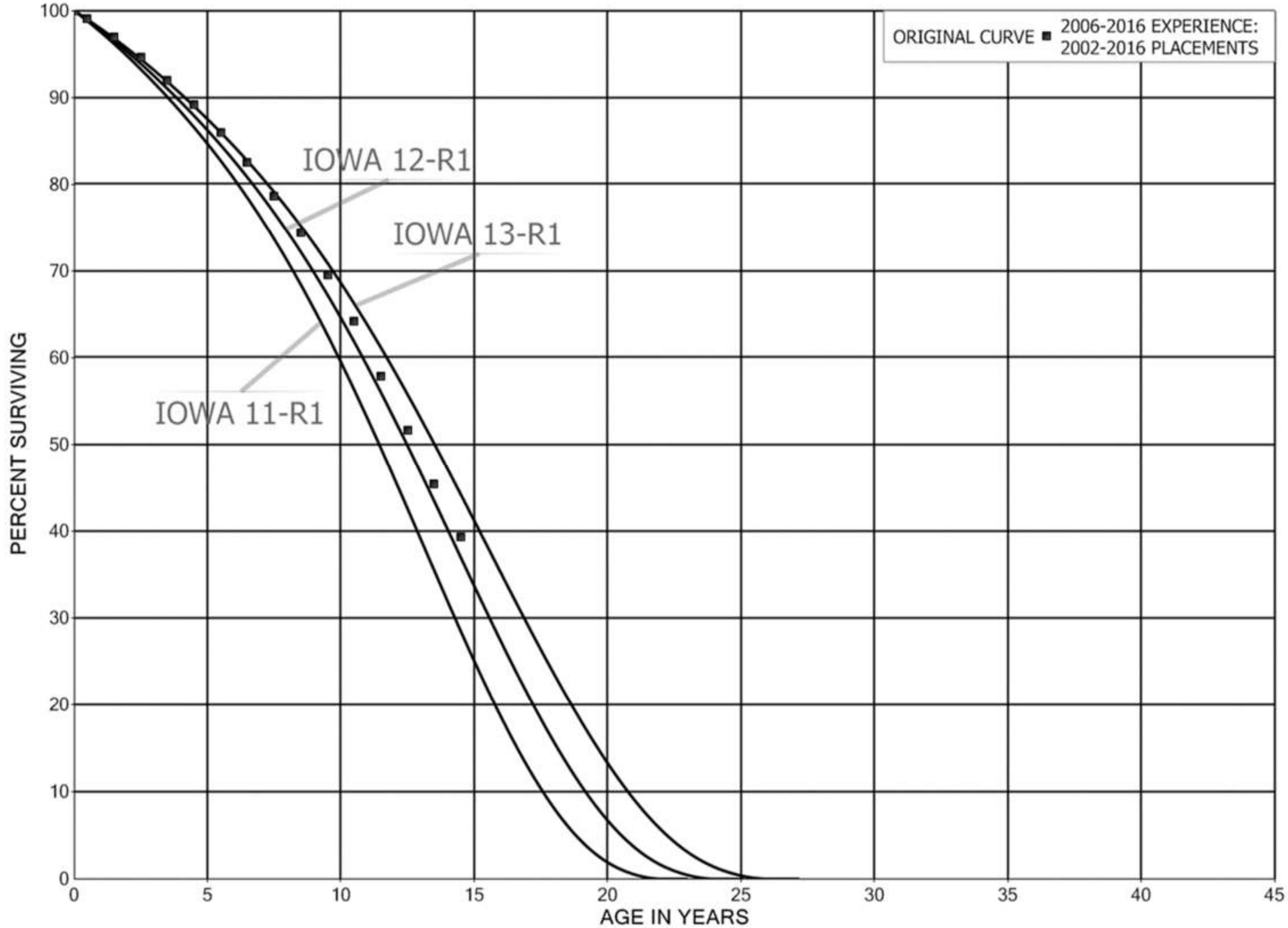
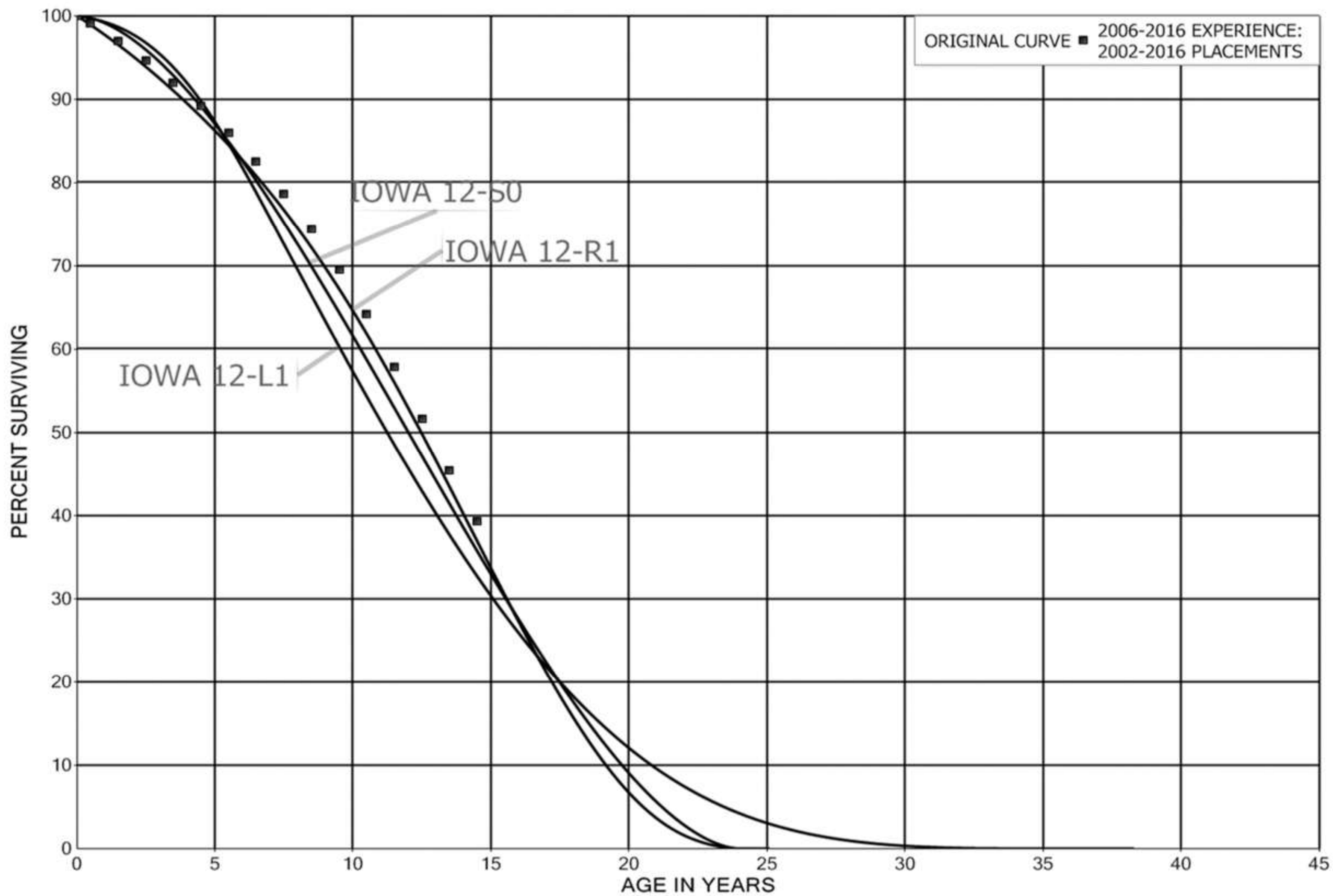


FIGURE 9: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES



SECTION 10

10 ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric, based in part on historical data, and in part through a comparison to Canadian peer companies. The analysis of historic net salvage activity considered gross salvage and cost of removal as recorded to the depreciation reserve account Net salvages as a percentage of the cost of plant retired are calculated for each plant component on both annual and three-year moving average bases.

The net salvage percentages for EGI were based on the Constant Dollar Net Salvage method. This method requires the recommended net salvage amounts to be initially determined using the "Traditional Approach" for net salvage estimation before being normalized to recognize the impacts of inflation of both the historic retirements and the future costs of removal. A detailed discussion of the CDNS method can be found beginning at page 3-11. The following discussion relates to the development of the traditional net salvage estimate which underlies the CDNS method.

When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceeds (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account's original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage as a percentage of the original cost is the result.

The estimation of the net salvage as a percentage of original cost as developed using the traditional approach, includes the following five steps.

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis is extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is also calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
4. Each account is then compared to the net salvage percentage currently approved, compared to Canadian peer companies, and discussed with company engineering staff. Based on the statistical

analysis, the review of current and Canadian peer company net salvage percentages, and with the professional judgment of Concentric, a net salvage percentage is determined for each account.

5. The net salvage percentage is then used in the depreciation rate calculations in the technical update or report.

APPENDIX 1 – DEPRECIATION CALCULATIONS USING A 2050 ECONOMIC PLANNING HORIZON

ENBRIDGE GAS INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account	Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LOCAL STORAGE PLANT										
442.00	STRUCTURES AND IMPROVEMENTS	2050	40-S5	0%	6,282,181	2,805,060	3,477,121	125,758	20.7	2.00%
443.01	HOLDER - STORAGE TANK	2050	45-R4	0%	5,804,412	4,023,544	1,780,869	70,878	15.8	1.22%
443.02	HOLDER EQUIPMENT	2050	55-R4	0%	21,554,522	11,363,396	10,191,126	366,664	24.5	1.70%
TOTAL LOCAL STORAGE PLANT					**33,641,115**	**18,192,000**	**15,449,115**	**563,300**		1.67%
UNDERGROUND STORAGE PLANT										
451.00	LAND RIGHTS INTANGIBLE	2050	55-R4	0%	74,762,354	45,841,825	28,920,529	1,306,142	20.2	1.75%
452.00	STRUCTURES AND IMPROVEMENTS	2050	40-R3	-11%	104,433,820	47,148,032	68,773,509	4,739,050	17.4	4.54%
453.00	WELLS	2050	45-R2.5	-34%	143,144,395	50,040,540	141,772,949	7,057,598	20.8	4.93%
454.00	WELL EQUIPMENT	2050	40-R2	0%	13,364,517	8,575,936	4,788,581	215,267	18.4	1.61%
455.00	FIELD LINES	2050	55-R3	-11%	201,920,080	53,298,115	170,833,174	7,264,186	23.8	3.60%
456.00	COMPRESSOR EQUIPMENT	2050	40-R4	-6%	682,328,757	228,311,196	494,957,286	23,065,924	21.6	3.38%
457.00	REGULATING AND MEASURING EQUIPMENT	2050	35-R3	-15%	77,194,133	51,829,828	36,943,425	2,303,495	14.7	2.98%
TOTAL UNDERGROUND STORAGE PLANT					**1,297,148,055**	**485,045,470**	**946,989,454**	**45,951,662**		3.54%
TRANSMISSION PLANT										
461.00	LAND RIGHTS INTANGIBLE	2050	60-R4	0%	88,171,402	20,599,533	67,571,869	2,473,684	27.1	2.81%
462.00	COMPRESSOR STRUCTURES AND IMPROVEMENTS	2050	50-S4	-6%	163,351,958	40,353,631	132,799,445	5,017,376	26.2	3.07%
463.00	MEASURING AND REGULATING STRUCTURES AND IMPROVEMENTS	2050	55-S4	-7%	11,252,284	7,167,268	4,872,675	206,037	21.1	1.83%
464.00	EQUIPMENT	2050	50-S4	-6%	2,920,218	523,642	2,571,789	100,528	26.3	3.44%
465.00	MAINS	2050	60-R4	-16%	2,783,251,797	919,330,147	2,309,241,938	86,187,728	26.0	3.10%
466.00	COMPRESSOR EQUIPMENT	2050	30-R4	-7%	1,005,060,039	331,530,582	743,883,660	38,321,598	19.2	3.81%
467.00	MEASURING AND REGULATING EQUIPMENT	2050	40-R4	-17%	395,646,542	119,798,512	343,107,942	14,756,768	23.1	3.73%
TOTAL TRANSMISSION PLANT					**4,449,654,239**	**1,439,303,314**	**3,604,049,317**	**147,063,719**		3.31%
DISTRIBUTION PLANT										
471.00	LAND RIGHTS INTANGIBLE	2050	60-R4	0%	63,907,560	12,099,619	51,807,941	1,904,842	27.1	2.98%
472.00 *	STRUCTURES AND IMPROVEMENTS - OTHER	2050	40-S0.5	0%	220,832,605	64,014,227	156,818,378	8,303,384	18.3	3.76%
472.31	STRUCTURES AND IMPROVEMENTS - STONEY CREEK	2046	40-S0.5	0%	29,662,115	5,056,171	24,605,944	1,325,428	18.6	4.47%
472.32	STRUCTURES AND IMPROVEMENTS - WIN-RHODES	2046	40-S0.5	0%	23,216,546	5,549,955	17,666,591	991,735	17.9	4.27%
472.33	STRUCTURES AND IMPROVEMENTS - LONDON ADMIN	2026	40-S0.5	0%	19,789,902	9,778,917	10,010,985	2,365,393	4.2	11.95%
472.34	STRUCTURES AND IMPROVEMENTS - KINGSTON OFFICE	2046	40-S0.5	0%	16,737,576	4,069,504	12,668,072	704,663	18.0	4.21%
472.35	STRUCTURES AND IMPROVEMENTS - MAINWAY	2023	40-S0.5	0%	15,937,297	3,958,252	11,979,045	8,045,939	1.5	50.48%
473.01	SERVICES - METAL	2050	45-S1	-36%	549,648,294	268,325,815	479,195,865	25,654,986	18.6	4.67%
473.02	SERVICES - PLASTIC	2050	55-S3	-32%	4,458,883,265	1,384,833,504	4,500,892,406	179,929,092	25.0	4.04%
474.00	REGULATORS	2050	25-SQ	0%	488,870,931	59,858,893	429,012,038	43,329,780	15.5	8.86%
475.00	MAINS - ENVISION	2050	25-SQ	0%	181,264,676	59,887,548	121,377,128	10,469,399	12.2	5.78%
475.21	MAINS - COATED & WRAPPED	2050	55-R3	-53%	3,320,418,328	1,051,359,036	4,028,881,007	176,679,582	23.6	5.32%
475.30	MAINS - PLASTIC	2050	60-R4	-51%	3,480,106,028	928,431,883	4,326,528,219	163,157,768	26.5	4.69%
476.00	COMPANY NGV COMPRESSOR STATIONS	2050	17-S2.5	0%	9,878,703	5,181,735	4,696,968	358,412	9.7	3.63%
477.00	MEASURING AND REGULATING EQUIPMENT	2050	40-R2	-10%	950,956,098	367,887,432	678,164,276	32,432,104	19.9	3.41%
477.01	CUSTOMER M&R EQUIPMENT	2050	35-R3	0%	143,726,981	52,094,469	91,632,512	5,183,135	17.7	3.61%
478.00	METERS	2050	15-S2.5	0%	1,020,910,894	469,525,898	551,384,996	104,686,352	6.4	10.25%
TOTAL DISTRIBUTION PLANT					**14,994,747,798**	**4,751,912,857**	**15,497,322,370**	**765,521,994**		5.11%
GENERAL PLANT										
482.00	STRUCTURES AND IMPROVEMENTS - OTHER	2050	40-R1.5	0%	13,255,572	8,677,610	4,577,962	234,463	19.6	1.77%
482.01	STRUCTURES AND IMPROVEMENTS - VPC	2033	40-R1.5	0%	53,463,354	19,270,729	34,192,626	3,400,629	10.0	6.36%
482.04	STRUCTURES AND IMPROVEMENTS - THOROLD	2022	40-R1.5	0%	15,678,640	6,391,978	9,286,662	9,286,663	0.5	59.23%
482.05	STRUCTURES AND IMPROVEMENTS - MARKHAM	2046	40-R1.5	0%	36,671,818	6,852,980	29,818,839	1,544,848	19.3	4.21%
482.51	STRUCTURES AND IMPROVEMENTS - KEIL HEAD OFFICE	2049	40-R1.5	0%	69,558,675	11,589,939	57,968,736	3,906,954	16.4	5.62%

ENBRIDGE GAS INC.

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO PLANT IN SERVICE AT DECEMBER 31, 2021

Related to Total Expense

Account	Description	Truncation Date	Estimated Survivor Curve	Net Salvage Percent	Surviving Original Cost as of 12/31/2021	Book Reserve	Future Accruals	Annual Accrual Amount	Composite Remaining Life	Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
482.52	STRUCTURES AND IMPROVEMENTS - BLOOMFIELD TRAINING CENTER	2028	40-R1.5	0%	19,237,692	1,664,764	17,572,928	2,814,701	6.2	14.63%
483.00	OFFICE FURNITURE AND EQUIPMENT	2050	15-SQ	0%	29,776,062	20,323,396	9,452,666	1,200,881	6.0	4.03%
484.00	TRANSPORTATION EQUIPMENT	2050	12-L2.5	0%	134,722,078	89,525,829	45,196,249	6,201,577	5.7	4.60%
485.00	HEAVY WORK EQUIPMENT	2050	17-L1.5	0%	44,128,921	12,811,266	31,317,655	3,664,830	8.6	8.30%
486.00	TOOLS AND WORK EQUIPMENT	2050	15-SQ	0%	79,966,854	26,128,214	53,838,641	9,529,666	7.6	11.92%
487.70	RENTAL - REFUEL APPL	2050	15-SQ	0%	864,755	92,164	772,591	86,895	9.3	10.05%
487.80	RENTAL - NGV STATIONS	2050	20-SQ	0%	7,774,175	2,397,143	5,377,032	288,265	18.4	3.71%
488.00	COMMUNICATION STRUCTURES AND EQUIPMENT	2050	10-SQ	0%	11,224,609	4,990,530	6,234,079	2,946,627	2.6	26.25%
490.00	COMPUTER EQUIPMENT	2050	4-SQ	0%	30,306,679	20,774,567	9,532,112	4,041,429	1.7	13.34%
	COMPUTER EQUIPMENT - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
490.30	COMPUTER EQUIPMENT - WAMS	2050	10-SQ	0%	4,680,899	2,418,465	2,262,435	502,763	4.5	10.74%
491.01	SOFTWARE ACQUIRED INTANGIBLES	2050	4-SQ	0%	155,164,785	107,550,337	47,614,448	13,604,128	2.0	8.77%
	SOFTWARE ACQUIRED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.02	SOFTWARE DEVELOPED INTANGIBLES	2050	4-SQ	0%	38,776,288	25,519,357	13,256,930	3,892,471	2.2	10.04%
	SOFTWARE DEVELOPED INTANGIBLES - POST 2023	0	4-SQ	0%	0	0	0	0	0.0	25.00%
491.03	CIS ACQUIRED SOFTWARE	2050	10-SQ	0%	87,626,214	20,250,171	67,376,042	7,217,716	8.4	8.24%
	** SOFTWARE INTANGIBLES - 10 YEAR	0	10-SQ	0%	0	0	0	0	0.0	10.00%
491.04	WAMS	2050	10-SQ	0%	85,221,905	44,031,318	41,190,587	9,153,464	4.5	10.74%
TOTAL GENERAL PLANT					**918,099,975**	**431,260,756**	**486,839,219**	**83,518,970**		9.10%
TOTAL UTILITY PLANT STUDIED					**21,693,291,183**	**7,125,714,397**	**20,550,649,476**	**1,042,619,645**		**4.81%**
PLANT NOT STUDIED										
401.00	Franchises and Consents - Total Comp				1,175,081					
402.04	Other Intangibles - Lakeland Acquisition Adjustment				494,761					
458.00	Base Pressure and Line Pack Gas				76,135,052					
	Land (Including MacLeod Property)				177,293,391					
	Plant Held for Future Use				1,670,861					
	Inventory Adjustment				59,309,971					
	** Post Study Adjustments				5,005,525					
TOTAL PLANT NOT STUDIED					**321,084,642**					
TOTAL UTILITY PLANT IN SERVICE					**22,014,375,825**					

* Annual Accrual Rates for new major structures in Account 472.00 after 2023 are 4.02%.
** New depreciation rate for major longer term intangible asset additions post 2023
** Adjustments between regulated and unregulated storage operations to align with updated exhibits in Enbridge Gas's 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding (EB-2022-0110), as filed on September 2, 2022

Enbridge Gas Distribution

Account #: 442.00 - Local Storage - Structures and Improvements
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S5
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1970	1,422,484.91	1,384,968	1,422,485	1.0000	0	1.40	0	51.5
1998	437,097.64	260,550	437,098	1.0000	0	15.92	0	23.5
2001	19,303.59	10,045	19,304	1.0000	0	18.90	0	20.5
2005	181,728.66	76,534	130,211	0.7165	51,518	22.68	2,272	16.5
2006	238,393.02	94,637	109,771	0.4605	128,622	23.55	5,463	15.5
2007	128,007.31	47,766	55,404	0.4328	72,603	24.36	2,981	14.5
2008	24,939.54	8,720	10,115	0.4056	14,824	25.11	590	13.5
2009	10,061.95	3,285	3,811	0.3787	6,251	25.78	242	12.5
2010	163,888.91	49,756	57,714	0.3522	106,175	26.38	4,025	11.5
2011	311,493.59	87,481	101,471	0.3258	210,023	26.89	7,811	10.5
2012	631,185.96	162,901	188,952	0.2994	442,234	27.31	16,194	9.5
2013	75,000.00	17,636	20,456	0.2727	54,544	27.65	1,973	8.5
2014	158,244.04	33,516	38,876	0.2457	119,368	27.91	4,277	7.5
2015	271,535.48	51,002	59,158	0.2179	212,378	28.11	7,556	6.5
2016	100,162.81	16,324	18,935	0.1890	81,228	28.25	2,876	5.5
2017	480,616.37	65,850	76,381	0.1589	404,236	28.34	14,262	4.5
2018	35,418.39	3,885	4,506	0.1272	30,912	28.41	1,088	3.5
2019	47,004.66	3,797	4,404	0.0937	42,600	28.45	1,497	2.5
2020	396,502.45	19,844	23,017	0.0580	373,486	28.47	13,118	1.5
2021	1,149,111.81	19,822	22,992	0.0200	1,126,120	28.49	39,533	0.5

Enbridge Gas Distribution

Account #: 442.00 - Local Storage - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S5
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	6,282,181.09	2,418,318	2,805,060		3,477,121		125,756	

COMPOSITE ANNUAL ACCRUAL RATE	2.00%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.45
COMPOSITE AVERAGE AGE (YEARS)	17.80
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	20.68

Enbridge Gas Inc.

Account #: 443.01 - Local Storage - Holder Storage Tank
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 45
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1969	2,186,400.39	2,040,876	2,186,400	1.0000	0	3.74	0	52.5
1999	2,066,786.98	1,082,880	1,622,218	0.7849	444,569	20.44	21,746	22.5
2002	320,890.28	149,712	182,535	0.5688	138,355	22.30	6,205	19.5
2016	24,428.41	4,096	4,994	0.2044	19,434	27.30	712	5.5
2017	10,174.29	1,432	1,747	0.1717	8,428	27.46	307	4.5
2021	1,195,732.11	21,037	25,649	0.0215	1,170,083	27.92	41,908	0.5
TOTAL	5,804,412.46	3,300,033	4,023,544		1,780,869		70,879	

COMPOSITE ANNUAL ACCRUAL RATE	1.22%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	29.00
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	15.84

Enbridge Gas Inc.

Account #: 443.02 - Local Storage - Holder Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 55
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1972	995,702.37	823,540	995,702	1.0000	0	10.35	0	49.5
1973	2,781,547.11	2,270,136	2,781,547	1.0000	0	10.93	0	48.5
1999	926,089.18	439,277	926,089	1.0000	0	24.93	0	22.5
2000	131,835.31	60,634	131,835	1.0000	0	25.25	0	21.5
2001	652,044.40	290,334	652,044	1.0000	0	25.54	0	20.5
2002	721,508.49	310,494	721,508	1.0000	0	25.81	0	19.5
2004	45,184.84	18,052	45,185	1.0000	0	26.30	0	17.5
2006	2,174,475.26	798,183	1,386,280	0.6375	788,195	26.73	29,491	15.5
2007	49,625.58	17,376	26,494	0.5339	23,132	26.91	859	14.5
2009	19,777.96	6,221	9,486	0.4796	10,292	27.24	378	12.5
2010	1,191,154.34	352,309	537,198	0.4510	653,956	27.38	23,883	11.5
2011	92,079.93	25,437	38,785	0.4212	53,295	27.51	1,937	10.5
2012	155,062.30	39,678	60,501	0.3902	94,561	27.63	3,423	9.5
2013	4,038,394.78	947,451	1,444,665	0.3577	2,593,730	27.73	93,534	8.5
2014	2,150,515.09	456,604	696,225	0.3237	1,454,290	27.82	52,268	7.5
2015	33,284.24	6,288	9,588	0.2881	23,696	27.91	849	6.5
2016	1,462,777.95	240,297	366,403	0.2505	1,096,375	27.98	39,184	5.5
2017	1,912,619.22	264,453	403,235	0.2108	1,509,384	28.05	53,819	4.5
2018	468,290.69	51,863	79,081	0.1689	389,210	28.10	13,850	3.5
2020	204,701.33	10,341	15,768	0.0770	188,934	28.19	6,701	1.5
2021	1,347,851.56	23,462	35,775	0.0265	1,312,077	28.22	46,488	0.5

Enbridge Gas Inc.

Account #: 443.02 - Local Storage - Holder Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 55
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	21,554,521.93	7,452,429	11,363,396		10,191,126		366,666	

COMPOSITE ANNUAL ACCRUAL RATE	1.70%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.53
COMPOSITE AVERAGE AGE (YEARS)	16.56
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	24.46

Enbridge Gas Inc.

Account #: 451.00 - Underground Storage - Land Rights Intangible
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 55
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1963	2,261,925.37	2,043,177	2,261,925	1.0000	0	6.26	0	58.5
1964	5,277,825.12	4,733,202	5,277,825	1.0000	0	6.62	0	57.5
1977	5,954,998.00	4,581,496	4,904,997	0.8237	1,050,001	13.34	78,706	44.5
1980	9,015.54	6,599	6,599	0.7320	2,416	15.19	159	41.5
1985	3,140.39	2,093	2,093	0.6665	1,047	18.26	57	36.5
1987	15,973,398.04	10,216,619	10,216,619	0.6396	5,756,779	19.44	296,134	34.5
1988	1,286,979.22	805,715	805,715	0.6261	481,264	20.01	24,051	33.5
1989	8,575,503.16	5,252,130	5,252,130	0.6125	3,323,373	20.56	161,604	32.5
1990	48.07	29	29	0.5989	19	21.10	1	31.5
1991	669,059.25	391,526	391,526	0.5852	277,533	21.62	12,837	30.5
1992	8,978.82	5,132	5,132	0.5715	3,847	22.12	174	29.5
1993	121,226.62	67,626	67,626	0.5579	53,600	22.59	2,373	28.5
1994	10,678,770.77	5,810,749	5,810,749	0.5441	4,868,021	23.04	211,300	27.5
1995	1,101,907.25	584,421	584,421	0.5304	517,486	23.46	22,054	26.5
1996	328,719.73	169,796	169,796	0.5165	158,924	23.87	6,659	25.5
1997	3,644,584.07	1,831,795	1,831,795	0.5026	1,812,789	24.25	74,767	24.5
1998	223,055.00	108,974	108,974	0.4886	114,081	24.60	4,637	23.5
1999	7,485,409.72	3,550,596	3,550,596	0.4743	3,934,814	24.93	157,804	22.5
2000	1,870,824.89	860,429	860,429	0.4599	1,010,396	25.25	40,020	21.5
2001	6,208,891.29	2,764,613	2,764,613	0.4453	3,444,278	25.54	134,859	20.5
2002	1,069,691.48	460,331	460,331	0.4303	609,360	25.81	23,607	19.5
2004	132,863.75	53,080	53,080	0.3995	79,784	26.30	3,033	17.5
2007	1,028.50	360	360	0.3501	668	26.91	25	14.5
2012	850,377.64	217,600	217,600	0.2559	632,778	27.63	22,905	9.5
2013	949,494.20	222,762	222,762	0.2346	726,733	27.73	26,207	8.5
2015	74,637.71	14,100	14,100	0.1889	60,537	27.91	2,169	6.5

Enbridge Gas Inc.

Account #: 451.00 - Underground Storage - Land Rights Intangible

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 55
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	74,762,353.60	44,754,952	45,841,825		28,920,529		1,306,143	

COMPOSITE ANNUAL ACCRUAL RATE	1.75%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.61
COMPOSITE AVERAGE AGE (YEARS)	32.10
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	20.17

Enbridge Gas Distribution

Account #: 452.00 - Underground Storage - Structures and Improvements
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -11%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1950	1,443,865.83	1,602,691	1,345,945	0.8398	256,746	0.00	256,746	71.5
1952	1,104,878.64	1,226,415	1,029,947	0.8398	196,468	0.00	196,468	69.5
1954	3,098,356.05	3,413,887	2,866,993	0.8336	572,183	0.50	572,183	67.5
1962	8,198.33	8,810	7,399	0.8131	1,701	1.96	869	59.5
1964	161,209.98	171,658	144,159	0.8056	34,784	2.44	14,254	57.5
1966	257.28	271	228	0.7978	58	2.92	20	55.5
1967	38,330.34	40,214	33,772	0.7938	8,775	3.16	2,775	54.5
1969	2,925.44	3,037	2,550	0.7854	697	3.64	192	52.5
1971	97,662.36	100,215	84,161	0.7764	24,244	4.13	5,874	50.5
1972	573,998.86	585,341	491,571	0.7715	145,568	4.38	33,232	49.5
1973	396,639.47	401,807	337,439	0.7664	102,831	4.64	22,149	48.5
1975	84,377.94	84,234	70,740	0.7553	22,920	5.20	4,405	46.5
1976	159,360.99	157,798	132,519	0.7492	44,372	5.51	8,060	45.5
1978	1,112,793.54	1,081,968	908,640	0.7356	326,561	6.16	53,008	43.5
1979	48,559.20	46,735	39,248	0.7282	14,652	6.52	2,249	42.5
1980	45,811.13	43,609	36,623	0.7202	14,227	6.89	2,065	41.5
1981	459,112.06	431,910	362,719	0.7118	146,895	7.29	20,160	40.5
1982	126,906.21	117,881	98,997	0.7028	41,869	7.70	5,436	39.5
1983	637,075.20	583,763	490,246	0.6933	216,908	8.14	26,654	38.5
1984	12,356.58	11,159	9,371	0.6832	4,345	8.59	506	37.5
1985	6,398,911.12	5,689,130	4,777,748	0.6727	2,325,043	9.07	256,353	36.5
1986	585,015.27	511,547	429,598	0.6616	219,769	9.56	22,978	35.5
1987	23,832.05	20,474	17,194	0.6500	9,260	10.08	919	34.5
1988	438,389.99	369,599	310,390	0.6379	176,222	10.61	16,615	33.5
1989	7,175,283.09	5,930,071	4,980,091	0.6253	2,984,473	11.15	267,663	32.5
1990	384,531.97	311,175	261,326	0.6122	165,505	11.71	14,136	31.5

Enbridge Gas Distribution

Account #: 452.00 - Underground Storage - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -11%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	10,690,648.49	8,460,893	7,105,483	0.5988	4,761,137	12.28	387,808	30.5
1992	1,442,301.45	1,115,022	936,399	0.5849	664,555	12.86	51,691	29.5
1993	4,619,528.91	3,484,184	2,926,028	0.5706	2,201,649	13.44	163,771	28.5
1994	1,045,497.63	768,327	645,244	0.5560	515,259	14.04	36,708	27.5
1995	1,766,850.15	1,263,476	1,061,071	0.5410	900,133	14.63	61,509	26.5
1996	694,194.79	482,386	405,109	0.5257	365,447	15.23	23,990	25.5
1997	3,980,697.34	2,684,072	2,254,091	0.5101	2,164,483	15.83	136,712	24.5
1998	1,097,522.69	716,993	602,133	0.4943	616,117	16.43	37,502	23.5
1999	356,921.57	225,553	189,420	0.4781	206,763	17.02	12,147	22.5
2000	437,532.69	267,007	224,233	0.4617	261,428	17.61	14,848	21.5
2001	262,245.39	154,265	129,552	0.4451	161,540	18.18	8,884	20.5
2002	32,408.17	18,340	15,402	0.4282	20,571	18.75	1,097	19.5
2003	52,561.38	28,554	23,980	0.4110	34,363	19.30	1,780	18.5
2004	5,134.95	2,672	2,244	0.3936	3,456	19.84	174	17.5
2005	120,335.65	59,796	50,217	0.3760	83,356	20.36	4,095	16.5
2006	6,134,325.97	2,902,658	2,437,661	0.3580	4,371,441	20.86	209,559	15.5
2007	165,148.76	74,158	62,278	0.3397	121,037	21.34	5,671	14.5
2008	2,022,148.64	858,258	720,767	0.3211	1,523,818	21.81	69,880	13.5
2009	1,127,927.98	450,382	378,232	0.3021	873,768	22.25	39,273	12.5
2010	3,231,053.01	1,207,078	1,013,708	0.2826	2,572,761	22.67	113,494	11.5
2011	2,648,624.28	919,634	772,311	0.2627	2,167,662	23.07	93,971	10.5
2012	3,093,659.63	990,249	831,614	0.2422	2,602,348	23.44	111,003	9.5
2013	448,471.88	131,009	110,022	0.2210	387,782	23.80	16,295	8.5
2014	2,896,331.69	762,321	640,199	0.1991	2,574,729	24.13	106,704	7.5
2015	860,535.48	200,681	168,533	0.1764	786,662	24.44	32,190	6.5
2016	15,595,267.55	3,150,164	2,645,517	0.1528	14,665,230	24.72	593,169	5.5

Enbridge Gas Distribution

Account #: 452.00 - Underground Storage - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -11%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	7,302,384.67	1,237,143	1,038,956	0.1282	7,066,691	24.98	282,853	4.5
2018	2,833,242.95	383,317	321,911	0.1024	2,822,989	25.22	111,954	3.5
2019	953,462.49	94,790	79,605	0.0752	978,738	25.41	38,514	2.5
2020	497,356.37	30,606	25,703	0.0466	526,363	25.56	20,596	1.5
2021	3,400,858.77	72,393	60,796	0.0161	3,714,158	25.57	145,239	0.5
TOTAL	104,433,820.29	56,141,776	47,148,032		68,773,509		4,739,051	

COMPOSITE ANNUAL ACCRUAL RATE	4.54%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.45
COMPOSITE AVERAGE AGE (YEARS)	21.28
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	17.40

Enbridge Gas Distribution

Account #: 453.00 - Underground Storage - Wells

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -34%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1930	104,556.07	140,105	100,573	0.7178	39,532	0.00	39,532	91.5
1944	136,898.18	180,877	129,841	0.7078	53,603	1.10	48,737	77.5
1948	199,945.48	258,778	185,761	0.6933	82,166	2.60	31,618	73.5
1951	93,734.88	120,009	86,148	0.6859	39,457	3.29	12,003	70.5
1952	77,656.86	99,077	71,121	0.6835	32,939	3.50	9,422	69.5
1953	134,260.49	170,687	122,526	0.6810	57,383	3.70	15,505	68.5
1954	624,444.06	790,993	567,808	0.6786	268,947	3.91	68,870	67.5
1955	821,267.15	1,036,506	744,048	0.6761	356,450	4.11	86,821	66.5
1957	668,745.36	837,498	601,192	0.6709	294,927	4.51	65,327	64.5
1959	213,743.90	265,465	190,562	0.6653	95,855	4.93	19,432	62.5
1960	56,120.82	69,397	49,816	0.6624	25,386	5.14	4,935	61.5
1962	77,124.21	94,487	67,827	0.6563	35,520	5.58	6,367	59.5
1963	154,668.29	188,551	135,350	0.6531	71,906	5.80	12,391	58.5
1964	383,488.89	465,091	333,862	0.6497	180,013	6.03	29,847	57.5
1965	34,719.32	41,879	30,062	0.6462	16,461	6.27	2,627	56.5
1966	297,332.41	356,594	255,978	0.6425	142,447	6.51	21,879	55.5
1968	152,156.75	180,217	129,367	0.6345	74,523	7.03	10,604	53.5
1969	349,341.25	410,951	294,998	0.6302	173,120	7.30	23,705	52.5
1970	247,704.72	289,281	207,658	0.6256	124,267	7.59	16,369	51.5
1971	1,817,702.23	2,106,447	1,512,096	0.6208	923,625	7.89	117,003	50.5
1972	181,715.80	208,861	149,930	0.6157	93,570	8.21	11,398	49.5
1973	112,820.71	128,549	92,278	0.6104	58,902	8.54	6,899	48.5
1974	662,545.00	747,953	536,912	0.6048	350,898	8.88	39,507	47.5
1975	182,511.82	204,022	146,455	0.5988	98,110	9.24	10,617	46.5
1976	56,281.42	62,261	44,694	0.5926	30,723	9.61	3,196	45.5
1977	1,081,721.94	1,183,502	849,568	0.5861	599,940	10.00	59,983	44.5

Enbridge Gas Distribution

Account #: 453.00 - Underground Storage - Wells

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -34%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1978	289,304.67	312,845	224,573	0.5793	163,095	10.40	15,676	43.5
1979	43,794.73	46,777	33,579	0.5722	25,106	10.82	2,321	42.5
1980	129,253.29	136,270	97,820	0.5648	75,379	11.25	6,702	41.5
1981	98,176.70	102,099	73,291	0.5571	58,266	11.69	4,986	40.5
1983	952,280.58	961,524	690,223	0.5409	585,833	12.59	46,517	38.5
1984	993,563.17	987,462	708,842	0.5324	622,533	13.06	47,665	37.5
1985	574,551.17	561,653	403,178	0.5237	366,720	13.53	27,098	36.5
1986	1,017,908.12	977,998	702,048	0.5147	661,949	14.01	47,244	35.5
1987	2,631,509.87	2,483,096	1,782,471	0.5055	1,743,753	14.49	120,316	34.5
1988	3,063,744.82	2,837,061	2,036,562	0.4961	2,068,856	14.98	138,138	33.5
1989	2,374,634.32	2,156,260	1,547,854	0.4864	1,634,156	15.46	105,699	32.5
1990	4,135,719.57	3,679,559	2,641,342	0.4766	2,900,522	15.94	181,933	31.5
1991	367,365.07	319,973	229,690	0.4666	262,579	16.42	15,988	30.5
1992	2,201,348.50	1,875,447	1,346,275	0.4564	1,603,532	16.90	94,888	29.5
1993	2,048,868.33	1,705,861	1,224,539	0.4460	1,520,945	17.37	87,566	28.5
1994	465,393.09	378,319	271,573	0.4355	352,054	17.83	19,743	27.5
1995	5,219,871.28	4,138,781	2,970,991	0.4248	4,023,637	18.29	220,044	26.5
1996	5,086,168.60	3,929,325	2,820,634	0.4139	3,994,832	18.73	213,284	25.5
1997	4,591,763.32	3,452,496	2,478,347	0.4028	3,674,616	19.16	191,752	24.5
1998	1,035,895.06	757,127	543,497	0.3915	844,602	19.58	43,126	23.5
1999	2,881,468.81	2,044,519	1,467,642	0.3801	2,393,526	19.99	119,723	22.5
2000	622,877.47	428,414	307,533	0.3685	527,123	20.39	25,855	21.5
2001	535,710.55	356,596	255,980	0.3566	461,872	20.77	22,240	20.5
2002	10,342,747.47	6,651,078	4,774,424	0.3445	9,084,858	21.13	429,881	19.5
2003	1,109,439.29	687,856	493,772	0.3321	992,877	21.48	46,215	18.5
2004	452,253.93	269,727	193,621	0.3195	412,399	21.82	18,901	17.5

Enbridge Gas Distribution

Account #: 453.00 - Underground Storage - Wells

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -34%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2005	1,360,580.25	778,555	558,880	0.3065	1,264,298	22.14	57,108	16.5
2006	996,980.51	545,749	391,762	0.2932	944,192	22.44	42,071	15.5
2007	571,778.84	298,398	214,203	0.2796	551,981	22.73	24,283	14.5
2008	1,208,898.37	599,096	430,056	0.2655	1,189,868	23.00	51,726	13.5
2009	1,775,954.26	831,847	597,135	0.2509	1,782,644	23.26	76,638	12.5
2010	11,625,733.52	5,118,434	3,674,227	0.2359	11,904,256	23.50	506,533	11.5
2011	926,645.91	380,936	273,452	0.2202	968,254	23.73	40,810	10.5
2012	3,611,156.89	1,374,963	987,006	0.2040	3,851,944	23.93	160,943	9.5
2013	1,210,191.93	422,512	303,297	0.1870	1,318,361	24.12	54,649	8.5
2014	2,286,760.05	722,788	518,848	0.1693	2,545,411	24.30	104,766	7.5
2015	2,024,005.52	569,645	408,915	0.1508	2,303,252	24.45	94,212	6.5
2016	7,066,060.81	1,731,587	1,243,006	0.1313	8,225,516	24.57	334,715	5.5
2017	539,683.06	111,554	80,078	0.1107	643,097	24.67	26,066	4.5
2018	11,744,935.60	1,951,165	1,400,628	0.0890	14,337,585	24.73	579,737	3.5
2019	499,285.70	61,426	44,095	0.0659	624,948	24.73	25,271	2.5
2020	8,527,709.20	656,402	471,193	0.0412	10,955,937	24.61	445,126	1.5
2021	24,979,214.43	678,464	487,030	0.0146	32,985,117	24.17	1,364,849	0.5
TOTAL	143,144,394.64	69,709,681	50,040,540		141,772,949		7,057,597	

COMPOSITE ANNUAL ACCRUAL RATE	4.93%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	16.36
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	20.76

Enbridge Gas Distribution

Account #: 454.00 - Underground Storage - Well Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1963	177,937.86	165,952	177,938	1.0000	0	4.23	0	58.5
1964	45,733.53	42,418	45,734	1.0000	0	4.49	0	57.5
1966	90,870.93	83,314	90,871	1.0000	0	5.03	0	55.5
1968	88,382.30	80,030	88,382	1.0000	0	5.58	0	53.5
1969	207,234.01	186,412	207,234	1.0000	0	5.86	0	52.5
1970	27,531.28	24,594	27,531	1.0000	0	6.15	0	51.5
1971	88,403.18	78,400	88,403	1.0000	0	6.44	0	50.5
1972	42,870.65	37,730	42,871	1.0000	0	6.74	0	49.5
1973	53,146.89	46,399	53,147	1.0000	0	7.05	0	48.5
1974	83,889.03	72,621	83,889	1.0000	0	7.37	0	47.5
1975	40,956.20	35,139	40,956	1.0000	0	7.70	0	46.5
1976	34,738.49	29,525	34,738	1.0000	0	8.03	0	45.5
1978	140,818.42	117,259	140,818	1.0000	0	8.74	0	43.5
1980	37,576.46	30,585	37,576	1.0000	0	9.49	0	41.5
1983	173,295.60	135,679	173,296	1.0000	0	10.67	0	38.5
1984	284,018.12	219,213	284,018	1.0000	0	11.09	0	37.5
1987	600,425.36	442,055	600,425	1.0000	0	12.36	0	34.5
1988	146,890.66	106,294	146,891	1.0000	0	12.79	0	33.5
1989	99,628.33	70,802	99,628	1.0000	0	13.23	0	32.5
1990	181,525.51	126,582	181,526	1.0000	0	13.67	0	31.5
1992	128,229.62	85,863	128,230	1.0000	0	14.56	0	29.5
1994	16,438.13	10,528	16,438	1.0000	0	15.44	0	27.5
1996	793,244.21	483,881	793,244	1.0000	0	16.30	0	25.5
1997	764,393.62	454,237	764,394	1.0000	0	16.73	0	24.5
1998	307,272.19	177,645	307,272	1.0000	0	17.15	0	23.5
1999	626,388.03	351,824	626,388	1.0000	0	17.56	0	22.5

Enbridge Gas Distribution

Account #: 454.00 - Underground Storage - Well Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2000	70,309.90	38,307	70,310	1.0000	0	17.96	0	21.5
2001	57,334.99	30,251	57,335	1.0000	0	18.35	0	20.5
2002	14,028.42	7,154	14,028	1.0000	0	18.74	0	19.5
2003	203,654.25	100,187	203,654	1.0000	0	19.11	0	18.5
2004	8,713.16	4,125	8,713	1.0000	0	19.46	0	17.5
2005	186,049.07	84,549	186,049	1.0000	0	19.81	0	16.5
2006	90,324.50	39,284	90,325	1.0000	0	20.14	0	15.5
2007	38,223.77	15,856	38,224	1.0000	0	20.46	0	14.5
2008	127,788.06	50,360	127,788	1.0000	0	20.76	0	13.5
2009	452,559.45	168,658	452,559	1.0000	0	21.04	0	12.5
2010	609,408.90	213,603	410,790	0.6741	198,619	21.31	9,321	11.5
2011	98,504.69	32,261	50,355	0.5112	48,149	21.56	2,233	10.5
2012	524,881.85	159,354	248,728	0.4739	276,153	21.79	12,673	9.5
2013	216,506.27	60,335	94,173	0.4350	122,333	22.00	5,560	8.5
2014	443,047.44	111,923	174,695	0.3943	268,352	22.19	12,094	7.5
2015	942,966.94	212,460	331,620	0.3517	611,347	22.35	27,354	6.5
2016	1,119,442.63	220,073	343,502	0.3069	775,941	22.48	34,522	5.5
2018	1,140,005.87	152,929	238,700	0.2094	901,306	22.59	39,897	3.5
2020	1,443,806.93	91,041	142,102	0.0984	1,301,705	22.29	58,403	1.5
2021	295,121.32	6,692	10,446	0.0354	284,676	21.55	13,210	0.5

Enbridge Gas Distribution

Account #: 454.00 - Underground Storage - Well Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	13,364,517.02	5,494,383	8,575,936		4,788,581		215,268	

COMPOSITE ANNUAL ACCRUAL RATE	1.61%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.64
COMPOSITE AVERAGE AGE (YEARS)	17.35
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	18.43

Enbridge Gas Distribution

Account #: 455.00 - Underground Storage - Field Lines

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -11%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1955	272,765.58	276,091	171,723	0.5672	131,047	6.43	20,393	66.5
1957	4,356.45	4,363	2,714	0.5612	2,122	6.98	304	64.5
1959	140,235.90	138,820	86,343	0.5547	69,318	7.58	9,142	62.5
1960	4,017.00	3,951	2,458	0.5512	2,001	7.90	253	61.5
1961	1,659,538.56	1,621,520	1,008,551	0.5475	833,537	8.23	101,286	60.5
1963	4,131,236.55	3,978,535	2,474,564	0.5396	2,111,108	8.93	236,478	58.5
1964	17,191.07	16,427	10,217	0.5354	8,865	9.30	954	57.5
1965	20,038.98	18,991	11,812	0.5310	10,431	9.68	1,078	56.5
1966	64,320.80	60,432	37,587	0.5265	33,809	10.07	3,358	55.5
1967	29,148.03	27,138	16,879	0.5217	15,475	10.48	1,477	54.5
1968	83,864.48	77,343	48,105	0.5168	44,984	10.89	4,130	53.5
1969	29,046.54	26,522	16,496	0.5116	15,745	11.32	1,391	52.5
1970	40,725.80	36,802	22,890	0.5064	22,316	11.76	1,898	51.5
1971	206,105.20	184,239	114,592	0.5009	114,184	12.21	9,353	50.5
1972	0.00	0	0	0.0000	0	12.66	0	49.5
1973	57,775.16	50,468	31,390	0.4895	32,741	13.13	2,494	48.5
1974	50,670.55	43,724	27,195	0.4835	29,049	13.60	2,136	47.5
1975	85,834.18	73,134	45,488	0.4774	49,788	14.08	3,537	46.5
1976	4,518,605.77	3,799,818	2,363,406	0.4712	2,652,246	14.56	182,176	45.5
1977	2,028,929.38	1,683,179	1,046,902	0.4649	1,205,210	15.04	80,126	44.5
1978	17,311.17	14,161	8,808	0.4584	10,407	15.53	670	43.5
1979	26,912.68	21,699	13,496	0.4518	16,377	16.01	1,023	42.5
1980	4,259.92	3,384	2,105	0.4451	2,624	16.49	159	41.5
1982	124,293.39	95,702	59,525	0.4314	78,441	17.44	4,497	39.5
1983	446,656.30	338,372	210,460	0.4245	285,328	17.91	15,931	38.5
1984	164,679.78	122,690	76,310	0.4175	106,484	18.37	5,796	37.5

Enbridge Gas Distribution

Account #: 455.00 - Underground Storage - Field Lines

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -11%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1985	761,952.26	558,015	347,074	0.4104	498,694	18.82	26,495	36.5
1986	22,979.98	16,535	10,285	0.4032	15,223	19.26	790	35.5
1987	6,330,534.25	4,473,472	2,782,405	0.3960	4,244,488	19.69	215,540	34.5
1988	1,232,367.16	854,797	531,666	0.3887	836,262	20.11	41,585	33.5
1989	205,491.17	139,829	86,971	0.3813	141,124	20.52	6,879	32.5
1990	597,014.44	398,310	247,741	0.3738	414,945	20.91	19,846	31.5
1991	4,306,848.74	2,815,551	1,751,213	0.3663	3,029,389	21.29	142,313	30.5
1992	32,053,202.42	20,518,983	12,762,373	0.3587	22,816,681	21.65	1,053,803	29.5
1993	489,237.92	306,460	190,612	0.3510	352,443	22.00	16,018	28.5
1994	1,444,423.00	884,660	550,240	0.3432	1,053,070	22.34	47,139	27.5
1995	20,739.05	12,408	7,718	0.3353	15,303	22.66	675	26.5
1996	3,574,761.51	2,087,412	1,298,326	0.3272	2,669,659	22.97	116,207	25.5
1997	8,871,581.69	5,050,550	3,141,335	0.3190	6,706,121	23.27	288,193	24.5
1998	1,316,983.06	730,107	454,111	0.3106	1,007,740	23.55	42,787	23.5
1999	7,563,883.83	4,078,071	2,536,474	0.3021	5,859,437	23.82	245,958	22.5
2000	1,318,514.97	690,339	429,376	0.2934	1,034,175	24.08	42,946	21.5
2001	5,290,704.84	2,685,637	1,670,409	0.2844	4,202,273	24.33	172,739	20.5
2002	6,565,346.39	3,225,161	2,005,982	0.2753	5,281,553	24.56	215,030	19.5
2003	2,377,916.74	1,128,110	701,661	0.2658	1,937,827	24.79	78,185	18.5
2004	2,770,988.88	1,266,577	787,784	0.2561	2,288,014	25.00	91,529	17.5
2005	818,209.01	359,370	223,521	0.2461	684,691	25.20	27,171	16.5
2006	2,199,942.90	925,618	575,715	0.2358	1,866,222	25.39	73,498	15.5
2007	679,282.81	272,823	169,690	0.2251	584,314	25.57	22,848	14.5
2008	7,248,883.16	2,767,753	1,721,484	0.2139	6,324,776	25.75	245,656	13.5
2009	969,493.90	350,218	217,828	0.2024	858,310	25.91	33,127	12.5
2010	1,258,563.41	427,690	266,014	0.1904	1,130,991	26.06	43,394	11.5

Enbridge Gas Distribution

Account #: 455.00 - Underground Storage - Field Lines

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -11%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2011	21,687,579.09	6,885,809	4,282,828	0.1779	19,790,385	26.21	755,109	10.5
2012	2,903,018.46	854,020	531,182	0.1648	2,691,168	26.34	102,151	9.5
2013	6,911,335.55	1,864,581	1,159,730	0.1512	6,511,852	26.47	245,989	8.5
2014	1,734,537.51	423,585	263,461	0.1368	1,661,876	26.59	62,500	7.5
2015	10,643,064.83	2,313,062	1,438,676	0.1218	10,375,126	26.70	388,606	6.5
2016	4,852,743.44	917,324	570,556	0.1059	4,815,989	26.80	179,727	5.5
2017	4,394,903.55	699,508	435,079	0.0892	4,443,264	26.88	165,282	4.5
2018	6,619,007.16	844,350	525,168	0.0715	6,821,930	26.96	253,084	3.5
2019	3,046,093.03	286,466	178,176	0.0527	3,202,987	27.01	118,596	2.5
2020	9,513,160.76	555,280	345,372	0.0327	10,214,236	27.03	377,953	1.5
2021	15,096,270.33	305,258	189,864	0.0113	16,566,996	26.95	614,798	0.5
TOTAL	201,920,080.43	85,691,204	53,298,115		170,833,174		7,264,185	

COMPOSITE ANNUAL ACCRUAL RATE	3.60%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.26
COMPOSITE AVERAGE AGE (YEARS)	18.42
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	23.78

Enbridge Gas Distribution

Account #: 456.00 - Underground Storage - Compressor Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -6%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1964	3,122,735.26	3,264,001	2,986,748	0.9023	323,351	0.81	323,351	57.5
1969	39,587.01	40,515	37,073	0.8835	4,889	1.88	2,607	52.5
1971	1,966,168.04	1,991,155	1,822,021	0.8742	262,117	2.36	111,148	50.5
1973	3,059,499.98	3,062,678	2,802,526	0.8642	440,544	2.86	154,216	48.5
1975	3,560,744.10	3,518,870	3,219,968	0.8531	554,420	3.38	164,198	46.5
1976	869,820.08	853,526	781,025	0.8471	140,984	3.65	38,618	45.5
1980	534,002.97	505,897	462,925	0.8178	103,118	4.93	20,900	41.5
1981	3,857,456.42	3,613,891	3,306,918	0.8088	781,986	5.32	146,897	40.5
1982	21,553,977.99	19,944,776	18,250,615	0.7988	4,596,601	5.75	799,660	39.5
1983	35,604.20	32,498	29,737	0.7879	8,003	6.21	1,289	38.5
1984	36,826.21	33,110	30,297	0.7761	8,738	6.71	1,302	37.5
1985	3,035,927.13	2,684,835	2,456,778	0.7634	761,305	7.25	105,016	36.5
1986	174,742.13	151,793	138,899	0.7499	46,328	7.82	5,925	35.5
1987	191,540.75	163,223	149,358	0.7356	53,675	8.41	6,379	34.5
1988	13,449,779.13	11,230,193	10,276,272	0.7208	3,980,494	9.03	440,888	33.5
1989	1,154,800.08	943,713	863,552	0.7055	360,537	9.66	37,339	32.5
1990	20,655,614.53	16,501,338	15,099,672	0.6896	6,795,280	10.30	659,988	31.5
1991	3,067,806.17	2,392,766	2,189,518	0.6733	1,062,356	10.95	97,011	30.5
1992	33,864,526.11	25,751,878	23,564,447	0.6565	12,331,950	11.62	1,061,175	29.5
1993	2,473,866.11	1,831,433	1,675,866	0.6391	946,432	12.31	76,901	28.5
1994	1,776,507.78	1,278,364	1,169,776	0.6212	713,322	13.01	54,833	27.5
1995	10,667,839.78	7,449,412	6,816,639	0.6028	4,491,271	13.73	327,210	26.5
1996	45,381,028.25	30,699,458	28,091,767	0.5840	20,012,123	14.46	1,384,280	25.5
1997	11,640,151.43	7,614,587	6,967,784	0.5647	5,370,776	15.20	353,354	24.5
1998	1,391,664.48	878,705	804,065	0.5451	671,099	15.95	42,071	23.5
1999	4,654,045.40	2,830,852	2,590,392	0.5251	2,342,896	16.71	140,205	22.5

Enbridge Gas Distribution

Account #: 456.00 - Underground Storage - Compressor Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -6%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2000	4,988,117.04	2,916,929	2,669,158	0.5048	2,618,246	17.47	149,852	21.5
2001	1,393,425.54	781,743	715,340	0.4843	761,691	18.23	41,776	20.5
2002	2,321,925.56	1,247,004	1,141,081	0.4636	1,320,160	18.99	69,528	19.5
2003	3,794,425.49	1,946,272	1,780,951	0.4428	2,241,140	19.73	113,582	18.5
2004	2,422,471.54	1,183,835	1,083,277	0.4219	1,484,543	20.46	72,563	17.5
2005	2,936,058.69	1,363,414	1,247,602	0.4009	1,864,620	21.16	88,103	16.5
2006	43,213,036.23	19,013,241	17,398,207	0.3798	28,407,611	21.84	1,300,603	15.5
2007	2,368,670.11	984,294	900,686	0.3587	1,610,105	22.49	71,600	14.5
2008	5,267,235.41	2,059,607	1,884,658	0.3376	3,698,611	23.10	160,138	13.5
2009	8,230,265.74	3,015,306	2,759,179	0.3163	5,964,903	23.67	252,047	12.5
2010	18,963,278.98	6,476,246	5,926,137	0.2948	14,174,938	24.19	585,889	11.5
2011	22,734,383.87	7,192,529	6,581,578	0.2731	17,516,869	24.68	709,758	10.5
2012	742,894.91	216,056	197,704	0.2511	589,765	25.13	23,473	9.5
2013	3,838,998.78	1,016,428	930,090	0.2286	3,139,249	25.53	122,962	8.5
2014	8,802,463.82	2,095,320	1,917,339	0.2055	7,413,273	25.90	286,248	7.5
2015	15,532,044.54	3,269,613	2,991,884	0.1817	13,472,084	26.23	513,605	6.5
2016	71,203,157.99	12,960,372	11,859,484	0.1571	63,615,863	26.53	2,397,928	5.5
2017	189,165,293.56	28,830,750	26,381,792	0.1316	174,133,419	26.80	6,498,222	4.5
2018	13,369,323.73	1,624,392	1,486,412	0.1049	12,685,071	27.03	469,216	3.5
2019	4,246,796.96	378,370	346,230	0.0769	4,155,375	27.24	152,528	2.5
2020	12,480,935.91	686,089	627,811	0.0475	12,601,981	27.42	459,518	1.5
2021	52,097,290.66	983,497	899,956	0.0163	54,323,172	27.57	1,970,024	0.5

Enbridge Gas Distribution

Account #: 456.00 - Underground Storage - Compressor Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -6%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	682,328,756.58	249,504,771	228,311,196		494,957,286		23,065,925	

COMPOSITE ANNUAL ACCRUAL RATE	3.38%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	13.53
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	21.62

Enbridge Gas Distribution

Account #: 457.00 - Underground Storage - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: -15%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1963	130,385.00	148,672	139,227	0.9285	10,716	0.50	10,716	58.5
1967	523,963.56	590,071	552,582	0.9171	49,976	1.15	43,333	54.5
1971	29,834.21	32,942	30,849	0.8992	3,460	2.10	1,651	50.5
1973	1,199,914.00	1,310,277	1,227,032	0.8892	152,869	2.58	59,318	48.5
1975	332,093.69	358,364	335,596	0.8787	46,311	3.05	15,160	46.5
1978	2,395,075.78	2,533,699	2,395,076	0.8696	359,261	3.79	94,841	43.5
1979	10,902.48	11,447	10,902	0.8696	1,635	4.05	404	42.5
1984	99,162.31	99,242	99,162	0.8696	14,874	5.59	2,661	37.5
1987	944,986.41	908,524	944,986	0.8696	141,748	6.77	20,946	34.5
1988	1,869,447.09	1,769,289	1,869,447	0.8696	280,417	7.21	38,915	33.5
1989	980,804.54	912,620	980,805	0.8696	147,121	7.67	19,188	32.5
1990	3,532,968.44	3,227,681	3,532,968	0.8696	529,945	8.15	65,014	31.5
1991	7,023,272.22	6,291,037	7,023,272	0.8696	1,053,491	8.66	121,685	30.5
1992	3,495,881.74	3,065,785	3,495,882	0.8696	524,382	9.18	57,095	29.5
1993	2,347,659.40	2,012,645	2,347,659	0.8696	352,149	9.73	36,190	28.5
1994	446,474.29	373,590	446,474	0.8696	66,971	10.29	6,505	27.5
1995	605,066.61	493,356	605,067	0.8696	90,760	10.88	8,345	26.5
1996	401,253.74	318,272	401,254	0.8696	60,188	11.47	5,247	25.5
1997	2,735,779.61	2,107,233	2,735,780	0.8696	410,367	12.08	33,973	24.5
1999	3,202,846.25	2,313,116	3,202,846	0.8696	480,427	13.33	36,047	22.5
2000	10,904,216.06	7,602,347	8,546,068	0.6815	3,993,780	13.96	286,013	21.5
2001	4,193,144.09	2,815,962	2,637,056	0.5469	2,185,059	14.60	149,614	20.5
2002	1,073,800.54	692,974	648,948	0.5255	585,923	15.25	38,424	19.5
2003	595,307.24	368,241	344,846	0.5037	339,758	15.89	21,377	18.5
2005	871,579.18	491,083	459,883	0.4588	542,433	17.18	31,579	16.5
2006	1,664,981.27	890,968	834,362	0.4358	1,080,366	17.81	60,660	15.5

Enbridge Gas Distribution

Account #: 457.00 - Underground Storage - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: -15%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	142,651.85	72,228	67,639	0.4123	96,411	18.43	5,230	14.5
2008	196,488.02	93,732	87,776	0.3885	138,185	19.04	7,256	13.5
2009	1,520,178.69	679,901	636,705	0.3642	1,111,500	19.64	56,591	12.5
2010	1,655,695.06	690,332	646,473	0.3395	1,257,576	20.22	62,198	11.5
2011	992,690.96	383,249	358,900	0.3144	782,695	20.78	37,672	10.5
2012	6,657,164.95	2,360,405	2,210,442	0.2887	5,445,297	21.31	255,500	9.5
2013	596,503.55	192,289	180,073	0.2625	505,906	21.82	23,182	8.5
2014	845,386.68	244,619	229,077	0.2356	743,117	22.31	33,313	7.5
2015	270,244.87	69,031	64,645	0.2080	246,136	22.76	10,813	6.5
2016	3,130,628.26	690,200	646,350	0.1795	2,953,873	23.19	127,382	5.5
2017	2,697,412.08	497,079	465,498	0.1501	2,636,526	23.58	111,801	4.5
2018	598,240.75	87,755	82,180	0.1195	605,797	23.94	25,306	3.5
2019	1,993,546.54	214,238	200,627	0.0875	2,091,952	24.25	86,256	2.5
2020	331,510.40	21,992	20,595	0.0540	360,642	24.50	14,718	1.5
2021	3,954,990.47	90,571	84,817	0.0186	4,463,422	24.61	181,376	0.5
TOTAL	77,194,132.88	48,127,059	51,829,828		36,943,425		2,303,496	

COMPOSITE ANNUAL ACCRUAL RATE	2.98%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.67
COMPOSITE AVERAGE AGE (YEARS)	20.48
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	14.72

Enbridge Gas Inc.

Account #: 461.00 - Transmission Plant - Land Rights Intangible

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1993	11,038.40	5,946	4,891	0.4431	6,148	24.41	252	28.5
1994	19,068,363.22	10,040,568	8,259,121	0.4331	10,809,242	24.73	437,159	27.5
1995	307,429.86	158,118	130,064	0.4231	177,366	25.02	7,088	26.5
1996	1,391,196.94	698,270	574,379	0.4129	816,818	25.30	32,279	25.5
1997	62,046.97	30,361	24,974	0.4025	37,073	25.57	1,450	24.5
1998	503,792.08	240,060	197,468	0.3920	306,324	25.82	11,865	23.5
1999	711,691.20	329,823	271,304	0.3812	440,387	26.05	16,905	22.5
2000	258.49	116	96	0.3702	163	26.27	6	21.5
2001	1,176,471.38	513,443	422,346	0.3590	754,126	26.47	28,487	20.5
2002	2,381,758.03	1,006,110	827,601	0.3475	1,554,157	26.66	58,291	19.5
2003	163,275.68	66,624	54,803	0.3356	108,473	26.84	4,042	18.5
2004	30,153.80	11,858	9,754	0.3235	20,400	27.00	756	17.5
2005	10,475.96	3,960	3,257	0.3109	7,219	27.15	266	16.5
2006	6,134,786.52	2,222,273	1,827,987	0.2980	4,306,800	27.29	157,821	15.5
2007	2,323,578.49	803,802	661,188	0.2846	1,662,391	27.42	60,637	14.5
2008	42,768.12	14,071	11,575	0.2706	31,193	27.53	1,133	13.5
2009	3,804,899.79	1,184,994	974,747	0.2562	2,830,153	27.64	102,407	12.5
2010	71,413.93	20,934	17,219	0.2411	54,194	27.73	1,954	11.5
2011	164,175.01	44,988	37,006	0.2254	127,169	27.82	4,571	10.5
2012	1,305.80	332	273	0.2090	1,033	27.90	37	9.5
2013	1,415,439.30	329,933	271,394	0.1917	1,144,045	27.97	40,909	8.5
2014	795,695.18	167,971	138,168	0.1736	657,527	28.03	23,459	7.5
2015	1,820,400.00	342,140	281,436	0.1546	1,538,964	28.08	54,798	6.5
2016	36,012,160.06	5,888,959	4,844,111	0.1345	31,168,049	28.13	1,107,859	5.5
2017	3,519,784.25	484,711	398,711	0.1133	3,121,073	28.18	110,766	4.5
2018	187,496.57	20,691	17,020	0.0908	170,476	28.22	6,042	3.5

Enbridge Gas Inc.

Account #: 461.00 - Transmission Plant - Land Rights Intangible
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2019	4,288,988.25	348,717	286,846	0.0669	4,002,142	28.25	141,677	2.5
2020	976,025.97	49,169	40,445	0.0414	935,581	28.28	33,088	1.5
2021	794,532.50	13,797	11,349	0.0143	783,184	28.29	27,680	0.5
TOTAL	88,171,401.75	25,042,738	20,599,533		67,571,869		2,473,683	

COMPOSITE ANNUAL ACCRUAL RATE	2.81%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	12.57
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	27.15

Enbridge Gas Distribution

Account #: 462.00 - Transmission Plant - Compressor Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 50
Net Salvage: -6%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1971	1,187,168.14	1,116,925	1,002,326	0.7965	256,072	6.40	40,033	50.5
1973	391,089.80	361,679	324,570	0.7829	89,985	7.09	12,691	48.5
1988	282,072.74	204,208	183,256	0.6129	115,741	15.55	7,443	33.5
1989	12,325,933.56	8,698,550	7,806,064	0.5975	5,259,425	16.32	322,348	32.5
1991	14,715,774.88	9,833,699	8,824,745	0.5657	6,773,976	17.88	378,843	30.5
1994	110,397.09	67,426	60,508	0.5171	56,513	20.23	2,794	27.5
1995	629,437.89	372,344	334,141	0.5008	333,063	20.99	15,871	26.5
1997	227,989.35	126,166	113,221	0.4685	128,447	22.43	5,727	24.5
1998	160,773.04	85,934	77,117	0.4525	93,303	23.10	4,038	23.5
2000	120,574.86	59,948	53,798	0.4209	74,012	24.34	3,041	21.5
2001	24,159.27	11,566	10,379	0.4053	15,230	24.89	612	20.5
2002	20,357.96	9,373	8,411	0.3898	13,169	25.40	519	19.5
2004	197,385.39	83,653	75,070	0.3588	134,158	26.27	5,107	17.5
2005	19,215.94	7,791	6,992	0.3433	13,377	26.64	502	16.5
2006	31,818.59	12,312	11,049	0.3276	22,679	26.96	841	15.5
2007	5,084,372.73	1,872,178	1,680,089	0.3117	3,709,346	27.24	136,167	14.5
2008	2,175,036.86	759,469	681,546	0.2956	1,623,993	27.48	59,092	13.5
2009	1,004,663.82	331,247	297,260	0.2791	767,684	27.69	27,727	12.5
2010	310,888.09	96,287	86,408	0.2622	243,133	27.86	8,727	11.5
2011	604,639.05	174,794	156,860	0.2447	484,058	28.00	17,288	10.5
2012	410,069.29	109,777	98,514	0.2266	336,160	28.12	11,956	9.5
2013	811,486.43	199,172	178,737	0.2078	681,439	28.21	24,156	8.5
2014	20,001,022.91	4,443,641	3,987,716	0.1881	17,213,368	28.28	608,605	7.5
2015	33,713,841.29	6,667,104	5,983,048	0.1674	29,753,623	28.34	1,049,845	6.5
2016	23,302,948.09	4,009,301	3,597,940	0.1457	21,103,185	28.39	743,456	5.5
2017	34,622,648.10	5,016,907	4,502,164	0.1227	32,197,843	28.42	1,132,981	4.5

Enbridge Gas Distribution

Account #: 462.00 - Transmission Plant - Compressor Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 50
Net Salvage: -6%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2018	154,780.99	17,977	16,132	0.0983	147,936	28.44	5,201	3.5
2019	189,237.30	16,197	14,535	0.0725	186,057	28.46	6,537	2.5
2020	268,143.29	14,224	12,764	0.0449	271,468	28.47	9,534	1.5
2021	10,254,031.19	187,509	168,270	0.0155	10,701,003	28.48	375,694	0.5
TOTAL	163,351,957.93	44,967,355	40,353,631		132,799,445		5,017,377	

COMPOSITE ANNUAL ACCRUAL RATE 3.07%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.25

COMPOSITE AVERAGE AGE (YEARS) 10.84

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 26.18

Enbridge Gas Distribution

Account #: 463.00 - Transmission Plant - Measuring and Regulating Structures and Improvements
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 55
Net Salvage: -7%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1931	583.35	616	624	1.0000	0	1.19	0	90.5
1954	826.60	834	871	0.9846	14	4.09	3	67.5
1958	322,414.22	320,300	334,461	0.9695	10,522	4.89	2,150	63.5
1959	3,884.40	3,842	4,011	0.9651	145	5.12	28	62.5
1960	170,882.37	168,193	175,629	0.9605	7,215	5.36	1,347	61.5
1961	68,923.58	67,494	70,478	0.9557	3,271	5.61	583	60.5
1962	19,415.52	18,910	19,746	0.9505	1,028	5.87	175	59.5
1963	5,480.23	5,307	5,541	0.9450	322	6.14	53	58.5
1964	82,870.60	79,755	83,281	0.9392	5,391	6.43	839	57.5
1965	113,466.20	108,482	113,466	0.9346	7,943	6.73	1,180	56.5
1966	12,889.72	12,237	12,890	0.9346	902	7.05	128	55.5
1968	16,260.15	15,199	16,260	0.9346	1,138	7.74	147	53.5
1969	11,439.49	10,601	11,439	0.9346	801	8.12	99	52.5
1970	3,366.51	3,091	3,367	0.9346	236	8.51	28	51.5
1971	12,064.50	10,970	12,065	0.9346	845	8.92	95	50.5
1972	4,526.37	4,073	4,526	0.9346	317	9.36	34	49.5
1973	7,696.36	6,848	7,696	0.9346	539	9.82	55	48.5
1974	96,065.03	84,466	96,065	0.9346	6,725	10.30	653	47.5
1975	55,403.35	48,098	55,403	0.9346	3,878	10.81	359	46.5
1976	12,794.87	10,959	12,795	0.9346	896	11.34	79	45.5
1977	88,859.03	75,020	88,859	0.9346	6,220	11.90	523	44.5
1978	80,811.59	67,191	80,812	0.9346	5,657	12.48	453	43.5
1979	99,637.42	81,514	99,637	0.9346	6,975	13.09	533	42.5
1981	238,599.34	188,459	238,599	0.9346	16,702	14.36	1,163	40.5
1982	146,799.48	113,772	146,799	0.9346	10,276	15.03	684	39.5
1983	45,243.40	34,374	45,243	0.9346	3,167	15.72	201	38.5

Enbridge Gas Distribution

Account #: 463.00 - Transmission Plant - Measuring and Regulating Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 55
Net Salvage: -7%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1984	229,535.79	170,793	229,536	0.9346	16,068	16.43	978	37.5
1985	23,764.54	17,302	23,765	0.9346	1,664	17.14	97	36.5
1986	627,855.34	446,915	627,855	0.9346	43,950	17.86	2,460	35.5
1987	841,421.49	585,067	729,900	0.8107	170,421	18.59	9,167	34.5
1988	22,839.52	15,501	16,186	0.6623	8,252	19.31	427	33.5
1989	791,278.65	523,792	546,949	0.6460	299,719	20.03	14,961	32.5
1990	785,719.08	506,921	529,333	0.6296	311,387	20.74	15,012	31.5
1991	996,030.58	625,897	653,569	0.6132	412,184	21.43	19,230	30.5
1992	337,836.22	206,643	215,779	0.5969	145,706	22.10	6,592	29.5
1993	713,832.36	424,748	443,527	0.5807	320,274	22.75	14,078	28.5
1994	97,420.36	56,357	58,848	0.5645	45,391	23.37	1,943	27.5
1995	926,577.87	520,806	543,831	0.5485	447,607	23.95	18,692	26.5
1997	47,478.23	25,145	26,257	0.5168	24,545	25.00	982	24.5
1998	104,058.13	53,437	55,799	0.5012	55,543	25.47	2,181	23.5
1999	5,385.29	2,679	2,798	0.4855	2,965	25.89	115	22.5
2000	49,451.57	23,813	24,865	0.4699	28,048	26.27	1,067	21.5
2002	289,511.03	130,121	135,874	0.4386	173,903	26.92	6,459	19.5
2005	125,526.90	50,227	52,447	0.3905	81,866	27.62	2,964	16.5
2006	162,810.09	62,370	65,127	0.3738	109,080	27.79	3,925	15.5
2007	272,875.71	99,764	104,175	0.3568	187,802	27.94	6,722	14.5
2008	432,488.79	150,335	156,981	0.3392	305,782	28.06	10,899	13.5
2009	8,146.72	2,680	2,799	0.3211	5,918	28.15	210	12.5
2010	20,858.65	6,460	6,745	0.3022	15,574	28.23	552	11.5
2011	84,169.67	24,374	25,451	0.2826	64,610	28.30	2,283	10.5
2012	203,670.58	54,700	57,118	0.2621	160,809	28.35	5,673	9.5
2013	3,000.00	740	772	0.2406	2,438	28.39	86	8.5

Enbridge Gas Distribution

Account #: 463.00 - Transmission Plant - Measuring and Regulating Structures and Improvements
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 55
Net Salvage: -7%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2014	16,610.27	3,711	3,875	0.2180	13,898	28.42	489	7.5
2016	210,132.56	36,415	38,025	0.1691	186,817	28.46	6,564	5.5
2017	54,330.04	7,934	8,285	0.1425	49,848	28.47	1,751	4.5
2018	48,913.00	5,728	5,981	0.1143	46,356	28.48	1,628	3.5
2019	212,068.09	18,307	19,116	0.0842	207,797	28.49	7,294	2.5
2021	785,483.10	14,493	15,134	0.0180	825,333	28.49	28,964	0.5
TOTAL	11,252,283.90	6,414,778	7,167,268		4,872,675		206,035	

COMPOSITE ANNUAL ACCRUAL RATE	1.83%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.64
COMPOSITE AVERAGE AGE (YEARS)	28.34
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	21.08

Enbridge Gas Distribution

Account #: 464.00 - Transmission Plant - Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life

Survivor Curve: S4

ASL: 50

Net Salvage: -6%

Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1931	698.96	741	586	0.7912	155	0.00	155	90.5
1948	681.35	703	557	0.7706	166	1.96	84	73.5
1950	589.52	606	480	0.7676	145	2.20	66	71.5
1952	892.48	914	723	0.7643	223	2.45	91	69.5
1953	5,232.50	5,345	4,229	0.7624	1,318	2.58	510	68.5
1954	817.91	833	659	0.7605	208	2.72	76	67.5
1955	104.89	107	84	0.7585	27	2.87	9	66.5
1960	6,978.68	6,979	5,522	0.7464	1,876	3.69	508	61.5
1961	49,895.81	49,703	39,326	0.7435	13,564	3.88	3,497	60.5
1962	8,662.20	8,593	6,799	0.7405	2,383	4.08	585	59.5
1963	6,687.24	6,605	5,226	0.7372	1,863	4.28	435	58.5
1967	16,358.53	15,823	12,519	0.7220	4,821	5.23	923	54.5
1969	1,290.60	1,232	975	0.7128	393	5.78	68	52.5
1970	1,257.77	1,192	944	0.7077	390	6.08	64	51.5
1975	5,102.82	4,626	3,660	0.6767	1,749	7.87	222	46.5
1981	7,801.40	6,525	5,163	0.6243	3,107	10.83	287	40.5
1987	55,785.33	41,380	32,740	0.5537	26,392	14.80	1,783	34.5
1988	17,757.05	12,855	10,171	0.5404	8,651	15.55	556	33.5
1989	17,076.29	12,051	9,535	0.5268	8,566	16.32	525	32.5
1991	29,342.88	19,608	15,514	0.4988	15,589	17.88	872	30.5
1992	45,070.75	29,259	23,150	0.4846	24,625	18.67	1,319	29.5
1994	14,615.78	8,927	7,063	0.4559	8,430	20.23	417	27.5
1995	76,532.46	45,273	35,821	0.4416	45,304	20.99	2,159	26.5
1996	123,181.55	70,511	55,789	0.4273	74,783	21.72	3,443	25.5
2014	9,027.77	2,006	1,587	0.1658	7,982	28.28	282	7.5
2016	1,316,312.85	226,473	179,190	0.1284	1,216,102	28.39	42,843	5.5

Enbridge Gas Distribution

Account #: 464.00 - Transmission Plant - Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S4
ASL: 50
Net Salvage: -6%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	2,606.59	378	299	0.1082	2,464	28.42	87	4.5
2019	927,988.75	79,427	62,844	0.0639	920,824	28.46	32,353	2.5
2021	171,866.85	3,143	2,487	0.0136	179,692	28.48	6,309	0.5
TOTAL	2,920,217.56	661,817	523,642		2,571,789		100,527	

COMPOSITE ANNUAL ACCRUAL RATE	3.44%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.18
COMPOSITE AVERAGE AGE (YEARS)	9.30
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	26.32

Enbridge Gas Distribution

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -16%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1900	504.57	585	585	1.0000	0	0.00	0	121.5
1910	13,248.18	15,368	15,368	1.0000	0	0.00	0	111.5
1921	33,733.67	39,131	39,131	1.0000	0	0.00	0	100.5
1926	7,918.72	9,186	9,186	1.0000	0	0.00	0	95.5
1927	69,978.99	81,176	81,176	1.0000	0	0.00	0	94.5
1928	40,173.58	46,601	46,601	1.0000	0	0.00	0	93.5
1930	61,570.86	71,034	61,571	0.8621	9,851	0.50	9,851	91.5
1931	156,074.83	180,027	156,075	0.8621	24,972	0.51	24,972	90.5
1935	124.68	143	125	0.8621	20	1.10	18	86.5
1936	751,729.53	859,099	751,730	0.8621	120,277	1.28	93,632	85.5
1937	408,311.87	465,409	408,312	0.8621	65,330	1.49	43,707	84.5
1938	150,740.66	171,362	150,741	0.8621	24,119	1.70	14,155	83.5
1939	139,371.43	158,000	139,371	0.8621	22,299	1.92	11,633	82.5
1940	166,120.78	187,759	166,121	0.8621	26,579	2.14	12,393	81.5
1941	259,663.51	292,584	259,664	0.8621	41,546	2.37	17,506	80.5
1942	231,275.70	259,770	231,276	0.8621	37,004	2.60	14,208	79.5
1943	63,399.04	70,970	63,399	0.8621	10,144	2.85	3,565	78.5
1945	67,400.64	74,924	67,401	0.8621	10,784	3.33	3,239	76.5
1946	307,753.16	340,843	307,753	0.8621	49,241	3.58	13,763	75.5
1947	639,932.51	706,060	639,933	0.8621	102,389	3.83	26,760	74.5
1948	1,858.42	2,043	1,858	0.8621	297	4.08	73	73.5
1950	49,994.63	54,497	49,995	0.8621	7,999	4.59	1,743	71.5
1951	1,184,149.93	1,285,216	1,184,150	0.8621	189,464	4.85	39,073	70.5
1952	11,672.21	12,611	11,672	0.8621	1,868	5.12	365	69.5
1953	1,068,946.00	1,149,485	1,068,946	0.8621	171,031	5.39	31,716	68.5
1954	167,992.60	179,756	167,993	0.8621	26,879	5.68	4,735	67.5

Enbridge Gas Distribution

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -16%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1955	670,889.45	714,106	670,889	0.8621	107,342	5.97	17,976	66.5
1956	121,386.63	128,491	121,387	0.8621	19,422	6.28	3,093	65.5
1957	17,289,437.66	18,193,603	17,289,438	0.8621	2,766,310	6.60	419,031	64.5
1958	19,410,275.93	20,297,201	19,410,276	0.8621	3,105,644	6.94	447,416	63.5
1959	3,170,065.01	3,292,711	3,170,065	0.8621	507,210	7.30	69,485	62.5
1960	973,648.73	1,004,065	973,649	0.8621	155,784	7.68	20,287	61.5
1961	842,536.00	862,192	842,536	0.8621	134,806	8.08	16,684	60.5
1962	2,095,941.04	2,127,213	2,095,941	0.8621	335,351	8.51	39,428	59.5
1963	907,327.59	912,763	907,328	0.8621	145,172	8.96	16,210	58.5
1964	10,668,880.18	10,632,190	10,668,880	0.8621	1,707,021	9.43	181,017	57.5
1965	5,558,167.09	5,483,737	5,558,167	0.8621	889,307	9.93	89,561	56.5
1966	6,082,507.70	5,937,456	6,082,508	0.8621	973,201	10.45	93,104	55.5
1967	9,103,641.70	8,787,353	9,103,642	0.8621	1,456,583	11.00	132,471	54.5
1968	3,358,225.53	3,203,536	3,358,226	0.8621	537,316	11.56	46,494	53.5
1969	1,939,472.95	1,827,477	1,939,473	0.8621	310,316	12.13	25,578	52.5
1970	6,615,568.92	6,154,436	6,615,569	0.8621	1,058,491	12.72	83,240	51.5
1971	9,268,739.44	8,509,586	9,268,739	0.8621	1,482,998	13.31	111,453	50.5
1972	12,962,889.20	11,740,517	12,962,889	0.8621	2,074,062	13.90	149,231	49.5
1973	2,587,292.63	2,310,871	2,587,293	0.8621	413,967	14.49	28,570	48.5
1974	4,701,695.38	4,139,681	4,701,695	0.8621	752,271	15.08	49,884	47.5
1975	26,894,698.08	23,334,387	26,894,698	0.8621	4,303,152	15.67	274,610	46.5
1976	4,453,962.91	3,806,607	4,453,963	0.8621	712,634	16.26	43,839	45.5
1977	1,105,639.75	930,468	1,105,640	0.8621	176,902	16.84	10,506	44.5
1978	3,650,138.28	3,023,631	3,650,138	0.8621	584,022	17.42	33,535	43.5
1979	11,045,642.38	9,003,051	11,045,642	0.8621	1,767,303	17.99	98,265	42.5
1980	2,363,387.55	1,894,752	2,363,388	0.8621	378,142	18.55	20,389	41.5

Enbridge Gas Distribution

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -16%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1981	19,253,434.14	15,177,015	19,253,434	0.8621	3,080,549	19.10	161,299	40.5
1982	31,736,353.72	24,589,528	31,736,354	0.8621	5,077,817	19.64	258,579	39.5
1983	585,609.64	445,823	585,610	0.8621	93,698	20.16	4,647	38.5
1984	18,409,411.00	13,765,777	18,409,411	0.8621	2,945,506	20.67	142,474	37.5
1985	40,319,036.48	29,602,806	40,319,036	0.8621	6,451,046	21.17	304,768	36.5
1986	10,355,630.60	7,462,817	10,355,631	0.8621	1,656,901	21.64	76,557	35.5
1987	6,381,187.02	4,511,984	6,381,187	0.8621	1,020,990	22.10	46,200	34.5
1988	33,840,488.10	23,468,122	33,840,488	0.8621	5,414,478	22.54	240,267	33.5
1989	64,565,346.35	43,896,578	50,555,301	0.6750	24,340,501	22.95	1,060,537	32.5
1990	35,227,934.04	23,469,615	18,517,800	0.4532	22,346,604	23.35	957,167	31.5
1991	33,945,460.29	22,149,958	17,476,575	0.4438	21,900,159	23.72	923,244	30.5
1992	69,166,629.12	44,178,546	34,857,388	0.4345	45,375,902	24.08	1,884,744	29.5
1993	35,102,013.98	21,932,761	17,305,204	0.4250	23,413,132	24.41	959,143	28.5
1994	34,556,578.01	21,107,343	16,653,940	0.4155	23,431,691	24.73	947,649	27.5
1995	30,037,510.10	17,920,813	14,139,731	0.4058	20,703,781	25.02	827,355	26.5
1996	51,558,774.26	30,018,919	23,685,277	0.3960	36,122,901	25.30	1,427,506	25.5
1997	19,704,937.40	11,184,887	8,825,006	0.3861	14,032,721	25.57	548,821	24.5
1998	34,226,277.63	18,918,508	14,926,923	0.3760	24,775,559	25.82	959,652	23.5
1999	53,916,470.45	28,984,676	22,869,247	0.3657	39,673,859	26.05	1,522,961	22.5
2000	17,677,659.48	9,229,520	7,282,199	0.3551	13,223,886	26.27	503,411	21.5
2001	46,466,250.25	23,523,763	18,560,523	0.3443	35,340,327	26.47	1,334,988	20.5
2002	51,922,238.74	25,442,467	20,074,403	0.3333	40,155,394	26.66	1,506,078	19.5
2003	7,521,099.34	3,559,978	2,808,864	0.3220	5,915,611	26.84	220,418	18.5
2004	4,659,850.83	2,125,682	1,677,188	0.3103	3,728,239	27.00	138,078	17.5
2005	11,997,470.67	5,260,596	4,150,672	0.2982	9,766,394	27.15	359,703	16.5
2006	125,125,575.60	52,577,757	41,484,463	0.2858	103,661,204	27.29	3,798,623	15.5

Enbridge Gas Distribution

Account #: 465.00 - Transmission Plant - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -16%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	80,961,603.56	32,488,456	25,633,770	0.2729	68,281,690	27.42	2,490,612	14.5
2008	11,216,023.81	4,280,717	3,377,536	0.2596	9,633,052	27.53	349,896	13.5
2009	45,004,705.67	16,258,820	12,828,398	0.2457	39,377,060	27.64	1,424,833	12.5
2010	8,923,405.41	3,034,236	2,394,047	0.2313	7,957,103	27.73	286,932	11.5
2011	15,874,783.26	5,046,051	3,981,393	0.2162	14,433,356	27.82	518,848	10.5
2012	41,321,828.47	12,176,942	9,607,749	0.2004	38,325,572	27.90	1,373,883	9.5
2013	69,144,443.21	18,696,027	14,751,383	0.1839	65,456,171	27.97	2,340,585	8.5
2014	41,414,560.89	10,141,389	8,001,674	0.1666	40,039,217	28.03	1,428,526	7.5
2015	156,789,681.68	34,183,195	26,970,940	0.1483	154,905,091	28.08	5,515,763	6.5
2016	671,012,315.57	127,285,170	100,429,483	0.1290	677,944,803	28.13	24,097,335	5.5
2017	200,758,114.35	32,069,892	25,303,518	0.1087	207,575,894	28.18	7,366,778	4.5
2018	15,795,859.13	2,022,081	1,595,446	0.0871	16,727,751	28.22	592,858	3.5
2019	99,159,853.46	9,352,171	7,378,972	0.0642	107,646,458	28.25	3,810,720	2.5
2020	73,822,444.83	4,313,970	3,403,772	0.0397	82,230,264	28.28	2,908,170	1.5
2021	189,897,248.28	3,825,066	3,018,022	0.0137	217,262,786	28.29	7,678,656	0.5
TOTAL	2,783,251,797.20	1,004,646,137	919,330,147		2,309,241,938		86,187,729	

COMPOSITE ANNUAL ACCRUAL RATE	3.10%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	15.26
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	25.95

Enbridge Gas Distribution

Account #: 466.00 - Transmission Plant - Compressor Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 30
Net Salvage: -7%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1970	5,225,157.68	5,590,919	5,475,799	0.9794	115,119	0.00	115,119	51.5
1972	6,694,440.19	7,163,051	7,015,561	0.9794	147,490	0.00	147,490	49.5
1988	3,767,639.42	3,707,591	3,631,250	0.9007	400,125	2.93	136,769	33.5
1990	29,064,577.31	27,933,720	27,358,553	0.8797	3,740,545	3.57	1,047,919	31.5
1993	4,270,487.16	3,905,489	3,825,073	0.8371	744,348	4.84	153,632	28.5
1994	6,598,676.71	5,906,971	5,785,344	0.8194	1,275,240	5.37	237,446	27.5
1995	11,074,974.21	9,680,461	9,481,136	0.8001	2,369,087	5.94	398,859	26.5
1996	41,359,020.59	35,220,151	34,494,953	0.7795	9,759,199	6.54	1,492,056	25.5
2001	2,237,627.66	1,617,269	1,583,968	0.6616	810,293	9.85	82,272	20.5
2004	1,108,053.64	700,901	686,469	0.5790	499,148	12.10	41,244	17.5
2006	6,339,908.87	3,598,424	3,524,330	0.5195	3,259,372	13.72	237,557	15.5
2007	81,039,112.91	43,264,408	42,373,576	0.4887	44,338,275	14.56	3,044,930	14.5
2008	80,181,083.22	40,048,201	39,223,591	0.4572	46,570,168	15.42	3,020,008	13.5
2009	1,978,036.78	918,753	899,835	0.4252	1,216,664	16.30	74,661	12.5
2010	5,756,021.34	2,469,422	2,418,575	0.3927	3,740,368	17.18	217,692	11.5
2011	17,185,515.58	6,757,235	6,618,100	0.3599	11,770,402	18.07	651,244	10.5
2012	33,368,237.21	11,915,754	11,670,404	0.3269	24,033,610	18.97	1,267,227	9.5
2013	1,949,552.75	625,455	612,577	0.2937	1,473,444	19.85	74,232	8.5
2014	6,525,504.74	1,855,916	1,817,702	0.2603	5,164,588	20.72	249,300	7.5
2015	203,461,376.38	50,433,949	49,395,493	0.2269	168,308,180	21.56	7,807,240	6.5
2016	153,100,505.79	32,335,923	31,670,113	0.1933	132,147,428	22.36	5,909,031	5.5
2017	235,646,157.74	41,075,005	40,229,253	0.1596	211,912,135	23.12	9,164,354	4.5
2018	2,388,189.10	327,261	320,523	0.1254	2,234,840	23.83	93,786	3.5
2019	620,131.22	61,500	60,234	0.0908	603,307	24.47	24,652	2.5
2020	1,757,876.43	106,264	104,076	0.0553	1,776,851	25.05	70,930	1.5
2021	62,362,174.13	1,280,458	1,254,093	0.0188	65,473,433	25.56	2,561,948	0.5

Enbridge Gas Distribution

Account #: 466.00 - Transmission Plant - Compressor Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 30
Net Salvage: -7%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	1,005,060,038.76	338,500,450	331,530,582		743,883,660		38,321,597	

COMPOSITE ANNUAL ACCRUAL RATE	3.81%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	9.59
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	19.17

Enbridge Gas Distribution

Account #: 467.00 - Transmission Plant - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -17%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1959	188,441.62	220,477	198,916	0.9022	21,561	0.00	21,561	62.5
1966	9,026.68	10,337	9,326	0.8831	1,235	1.20	1,027	55.5
1968	11,759.11	13,348	12,043	0.8753	1,715	1.64	1,044	53.5
1970	18,456.51	20,742	18,714	0.8666	2,880	2.11	1,362	51.5
1971	7,194.17	8,042	7,255	0.8620	1,162	2.36	493	50.5
1972	11,696.49	13,001	11,729	0.8571	1,956	2.61	751	49.5
1973	8,407.17	9,289	8,381	0.8520	1,456	2.86	510	48.5
1974	1,862.82	2,045	1,845	0.8467	334	3.11	107	47.5
1975	59,355.58	64,745	58,413	0.8411	11,033	3.38	3,268	46.5
1976	31,572.65	34,196	30,852	0.8352	6,088	3.65	1,668	45.5
1977	376,455.39	404,634	365,064	0.8288	75,388	3.94	19,138	44.5
1978	178,048.72	189,791	171,231	0.8220	37,086	4.25	8,734	43.5
1979	927,242.77	979,414	883,635	0.8145	201,239	4.58	43,975	42.5
1980	479,947.53	501,871	452,792	0.8063	108,747	4.93	22,041	41.5
1981	294,824.68	304,872	275,058	0.7974	69,887	5.32	13,128	40.5
1982	440,527.13	449,940	405,939	0.7876	109,478	5.75	19,046	39.5
1983	549,778.12	553,888	499,722	0.7769	143,518	6.21	23,108	38.5
1984	524,308.07	520,314	469,431	0.7652	144,009	6.71	21,456	37.5
1985	152,873.85	149,224	134,631	0.7527	44,231	7.25	6,101	36.5
1986	747,775.12	716,975	646,861	0.7394	228,036	7.82	29,163	35.5
1987	1,032,489.94	971,148	876,177	0.7253	331,836	8.41	39,436	34.5
1988	542,274.92	499,772	450,898	0.7107	183,564	9.03	20,332	33.5
1989	1,145,802.99	1,033,530	932,459	0.6956	408,131	9.66	42,268	32.5
1990	3,690,685.77	3,254,379	2,936,126	0.6800	1,381,976	10.30	134,224	31.5
1991	4,736,358.91	4,077,528	3,678,778	0.6639	1,862,762	10.95	170,102	30.5
1992	4,637,724.55	3,892,681	3,512,008	0.6472	1,914,130	11.62	164,713	29.5

Enbridge Gas Distribution

Account #: 467.00 - Transmission Plant - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -17%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1993	4,885,103.21	3,991,798	3,601,432	0.6301	2,114,139	12.31	171,782	28.5
1994	20,380,731.29	16,187,770	14,604,734	0.6125	9,240,722	13.01	710,334	27.5
1995	27,519,668.78	21,211,368	19,137,064	0.5944	13,060,949	13.73	951,552	26.5
1996	9,287,945.53	6,935,153	6,256,950	0.5758	4,609,947	14.46	318,879	25.5
1997	3,029,524.31	2,187,470	1,973,553	0.5568	1,570,990	15.20	103,359	24.5
1998	1,600,719.85	1,115,588	1,006,492	0.5374	866,350	15.95	54,311	23.5
1999	1,407,652.27	945,065	852,646	0.5177	794,308	16.71	47,534	22.5
2000	3,391,667.93	2,189,186	1,975,100	0.4977	1,993,151	17.47	114,075	21.5
2001	312,821.79	193,712	174,769	0.4775	191,233	18.23	10,488	20.5
2002	3,206,373.95	1,900,701	1,714,828	0.4571	2,036,630	18.99	107,261	19.5
2003	1,350,524.87	764,610	689,837	0.4366	890,277	19.73	45,120	18.5
2004	416,252.54	224,527	202,570	0.4159	284,445	20.46	13,903	17.5
2005	5,596,399.00	2,868,479	2,587,965	0.3952	3,959,822	21.16	187,102	16.5
2006	3,535,621.39	1,717,066	1,549,151	0.3745	2,587,526	21.84	118,466	15.5
2007	4,980,458.12	2,284,386	2,060,991	0.3537	3,766,145	22.49	167,478	14.5
2008	6,195,518.94	2,673,987	2,412,492	0.3328	4,836,265	23.10	209,395	13.5
2009	6,608,911.49	2,672,560	2,411,205	0.3118	5,321,221	23.67	224,848	12.5
2010	4,445,096.77	1,675,603	1,511,742	0.2907	3,689,021	24.19	152,477	11.5
2011	7,466,619.58	2,607,369	2,352,389	0.2693	6,383,556	24.68	258,652	10.5
2012	7,756,083.19	2,489,785	2,246,303	0.2475	6,828,314	25.13	271,773	9.5
2013	5,873,761.25	1,716,544	1,548,680	0.2254	5,323,621	25.53	208,521	8.5
2014	24,750,303.78	6,502,895	5,866,963	0.2026	23,090,892	25.90	891,608	7.5
2015	29,969,409.90	6,963,473	6,282,500	0.1792	28,781,709	26.23	1,097,265	6.5
2016	32,234,134.41	6,476,110	5,842,797	0.1549	31,871,140	26.53	1,201,347	5.5
2017	50,655,952.22	8,521,675	7,688,322	0.1297	51,579,142	26.80	1,924,804	4.5
2018	13,659,429.31	1,831,867	1,652,725	0.1034	14,328,807	27.03	530,017	3.5

Enbridge Gas Distribution

Account #: 467.00 - Transmission Plant - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 40
Net Salvage: -17%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2019	26,497,560.27	2,605,797	2,350,971	0.0758	28,651,175	27.24	1,051,672	2.5
2020	25,594,737.74	1,552,973	1,401,105	0.0468	28,544,738	27.42	1,040,853	1.5
2021	42,232,666.74	880,008	793,950	0.0161	48,618,270	27.57	1,763,136	0.5
TOTAL	395,646,541.68	132,783,710	119,798,512		343,107,942		14,756,768	

COMPOSITE ANNUAL ACCRUAL RATE	3.73%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.30
COMPOSITE AVERAGE AGE (YEARS)	10.81
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	23.08

Enbridge Gas Distribution

Account #: 471.00 - Distribution - Land Rights

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1982	734,045.10	490,296	345,092	0.4701	388,953	19.64	19,807	39.5
1983	73,108.81	47,981	33,771	0.4619	39,338	20.16	1,951	38.5
1984	173,766.21	112,013	78,840	0.4537	94,927	20.67	4,592	37.5
1985	3,426,337.47	2,168,677	1,526,412	0.4455	1,899,926	21.17	89,758	36.5
1986	958,048.88	595,190	418,922	0.4373	539,127	21.64	24,910	35.5
1987	354,429.13	216,042	152,060	0.4290	202,369	22.10	9,157	34.5
1988	100,679.11	60,190	42,364	0.4208	58,315	22.54	2,588	33.5
1989	57,560.44	33,736	23,745	0.4125	33,815	22.95	1,473	32.5
1990	233,617.04	134,173	94,437	0.4042	139,180	23.35	5,961	31.5
1991	115,800.71	65,140	45,848	0.3959	69,953	23.72	2,949	30.5
1992	108,308.90	59,638	41,976	0.3876	66,333	24.08	2,755	29.5
1993	151,770.02	81,750	57,539	0.3791	94,231	24.41	3,860	28.5
1994	3,464,454.84	1,824,231	1,283,975	0.3706	2,180,480	24.73	88,185	27.5
1995	498,278.96	256,276	180,379	0.3620	317,900	25.02	12,704	26.5
1996	331,266.13	166,269	117,028	0.3533	214,239	25.30	8,466	25.5
1997	389,245.74	190,468	134,060	0.3444	255,186	25.57	9,980	24.5
1998	491,767.35	234,331	164,932	0.3354	326,835	25.82	12,660	23.5
1999	286,264.03	132,665	93,375	0.3262	192,889	26.05	7,404	22.5
2000	164,849.29	74,197	52,223	0.3168	112,626	26.27	4,288	21.5
2001	125,436.04	54,744	38,531	0.3072	86,905	26.47	3,283	20.5
2002	183,136.39	77,361	54,450	0.2973	128,686	26.66	4,827	19.5
2003	122,559.25	50,010	35,199	0.2872	87,360	26.84	3,255	18.5
2004	85,791.29	33,737	23,746	0.2768	62,045	27.00	2,298	17.5
2005	196,577.85	74,306	52,300	0.2661	144,278	27.15	5,314	16.5
2006	203,679.93	73,781	51,931	0.2550	151,749	27.29	5,561	15.5
2007	233,697.12	80,844	56,901	0.2435	176,796	27.42	6,449	14.5

Enbridge Gas Distribution

Account #: 471.00 - Distribution - Land Rights

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life

Survivor Curve: R4

ASL: 60

Net Salvage: 0%

Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2008	7,953,167.56	2,616,735	1,841,775	0.2316	6,111,393	27.53	221,981	13.5
2009	499,300.58	155,502	109,449	0.2192	389,852	27.64	14,107	12.5
2010	230,269.02	67,499	47,509	0.2063	182,760	27.73	6,590	11.5
2011	252,988.91	69,325	48,794	0.1929	204,195	27.82	7,340	10.5
2012	399,570.90	101,507	71,445	0.1788	328,126	27.90	11,763	9.5
2013	541,565.43	126,237	88,851	0.1641	452,715	27.97	16,188	8.5
2014	4,486,011.49	946,993	666,536	0.1486	3,819,476	28.03	136,272	7.5
2015	476,115.17	89,485	62,983	0.1323	413,132	28.08	14,711	6.5
2016	33,197,490.81	5,428,684	3,820,950	0.1151	29,376,541	28.13	1,044,180	5.5
2017	354,078.01	48,760	34,320	0.0969	319,758	28.18	11,348	4.5
2018	499,779.33	55,154	38,820	0.0777	460,960	28.22	16,337	3.5
2019	611,812.17	49,744	35,012	0.0572	576,800	28.25	20,419	2.5
2020	826,239.39	41,623	29,296	0.0355	796,943	28.28	28,185	1.5
2021	314,694.85	5,465	3,846	0.0122	310,849	28.29	10,986	0.5
TOTAL	63,907,559.65	17,190,754	12,099,619		51,807,941		1,904,842	

COMPOSITE ANNUAL ACCRUAL RATE 2.98%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.19

COMPOSITE AVERAGE AGE (YEARS) 11.80

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 27.07

Enbridge Gas Distribution

Account #: 472.00 - Distribution - Structures - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1928	39,923.45	39,923	34,039	0.8526	5,884	0.00	5,884	93.5
1929	1,751.32	1,751	1,493	0.8526	258	0.00	258	92.5
1930	6,119.60	6,120	5,218	0.8526	902	0.00	902	91.5
1937	96.35	96	82	0.8526	14	0.00	14	84.5
1939	4,831.67	4,832	4,120	0.8526	712	0.00	712	82.5
1940	1,334.00	1,334	1,137	0.8526	197	0.00	197	81.5
1941	244.99	245	209	0.8526	36	0.00	36	80.5
1947	211.52	206	176	0.8310	36	1.94	18	74.5
1948	502.38	487	416	0.8271	87	2.27	38	73.5
1949	340.83	329	281	0.8232	60	2.59	23	72.5
1952	6,519.54	6,203	5,289	0.8112	1,231	3.55	347	69.5
1953	1,030.38	975	832	0.8071	199	3.86	51	68.5
1954	244,600.76	230,347	196,396	0.8029	48,204	4.18	11,541	67.5
1956	248,675.48	231,694	197,545	0.7944	51,131	4.80	10,651	65.5
1957	26,308.73	24,377	20,784	0.7900	5,525	5.11	1,081	64.5
1958	481,214.00	443,365	378,018	0.7856	103,196	5.42	19,037	63.5
1959	1,017,508.01	932,060	794,684	0.7810	222,824	5.73	38,889	62.5
1960	1,029,622.81	937,568	799,380	0.7764	230,243	6.04	38,130	61.5
1961	367,420.70	332,537	283,524	0.7717	83,896	6.35	13,219	60.5
1962	885,238.46	796,189	678,840	0.7668	206,399	6.65	31,015	59.5
1963	68,372.27	61,100	52,095	0.7619	16,278	6.96	2,338	58.5
1964	487,356.37	432,648	368,881	0.7569	118,476	7.27	16,295	57.5
1965	92,352.29	81,429	69,427	0.7518	22,925	7.58	3,025	56.5
1966	111,478.42	97,607	83,220	0.7465	28,258	7.89	3,583	55.5
1967	113,272.42	98,464	83,951	0.7411	29,321	8.20	3,577	54.5
1968	7,137,865.37	6,158,700	5,250,973	0.7357	1,886,892	8.51	221,833	53.5

Enbridge Gas Distribution

Account #: 472.00 - Distribution - Structures - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1969	1,425,993.59	1,220,967	1,041,010	0.7300	384,984	8.82	43,669	52.5
1970	43,915.34	37,304	31,806	0.7243	12,109	9.13	1,327	51.5
1971	427,607.50	360,278	307,177	0.7184	120,430	9.44	12,761	50.5
1972	205,086.10	171,344	146,090	0.7123	58,996	9.75	6,052	49.5
1973	139,443.32	115,496	98,473	0.7062	40,970	10.06	4,074	48.5
1974	15,224,527.59	12,498,020	10,655,944	0.6999	4,568,583	10.36	440,882	47.5
1975	34,356.61	27,946	23,827	0.6935	10,529	10.67	987	46.5
1976	118,650.93	95,607	81,516	0.6870	37,135	10.97	3,386	45.5
1977	973,962.60	777,227	662,672	0.6804	311,291	11.26	27,636	44.5
1978	4,746.86	3,750	3,198	0.6736	1,549	11.56	134	43.5
1979	43,220.27	33,797	28,816	0.6667	14,404	11.85	1,216	42.5
1980	975,054.36	754,418	643,225	0.6597	331,829	12.14	27,340	41.5
1981	1,478,165.14	1,131,219	964,489	0.6525	513,676	12.42	41,354	40.5
1982	2,062,178.80	1,560,387	1,330,403	0.6451	731,776	12.70	57,609	39.5
1983	915,606.25	684,744	583,820	0.6376	331,786	12.98	25,561	38.5
1984	257,314.51	190,115	162,094	0.6299	95,220	13.25	7,184	37.5
1985	1,375,714.09	1,003,739	855,798	0.6221	519,916	13.53	38,437	36.5
1986	318,773.12	229,565	195,730	0.6140	123,043	13.80	8,919	35.5
1987	720,426.42	511,828	436,390	0.6057	284,037	14.06	20,201	34.5
1988	721,418.62	505,348	430,865	0.5972	290,553	14.32	20,285	33.5
1989	1,319,056.66	910,495	776,297	0.5885	542,759	14.58	37,217	32.5
1990	527,425.71	358,514	305,673	0.5796	221,753	14.84	14,942	31.5
1991	1,793,157.64	1,199,476	1,022,686	0.5703	770,472	15.10	51,038	30.5
1992	633,017.80	416,380	355,010	0.5608	278,008	15.35	18,113	29.5
1993	706,848.03	456,818	389,488	0.5510	317,360	15.60	20,345	28.5
1994	3,260,358.72	2,068,423	1,763,560	0.5409	1,496,799	15.85	94,453	27.5

Enbridge Gas Distribution

Account #: 472.00 - Distribution - Structures - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1995	11,944,393.09	7,431,418	6,336,106	0.5305	5,608,287	16.09	348,492	26.5
1996	1,350,706.55	823,265	701,924	0.5197	648,782	16.34	39,712	25.5
1997	8,462,798.23	5,047,271	4,303,356	0.5085	4,159,442	16.58	250,881	24.5
1998	911,442.78	531,225	452,928	0.4969	458,515	16.82	27,260	23.5
1999	767,871.44	436,746	372,374	0.4849	395,497	17.06	23,184	22.5
2000	451,349.63	250,129	213,263	0.4725	238,087	17.30	13,765	21.5
2001	203,608.45	109,749	93,573	0.4596	110,035	17.53	6,276	20.5
2002	4,289,775.17	2,244,668	1,913,828	0.4461	2,375,948	17.77	133,733	19.5
2003	2,025,648.86	1,026,711	875,385	0.4322	1,150,264	18.00	63,905	18.5
2004	1,615,369.24	791,149	674,542	0.4176	940,827	18.23	51,604	17.5
2005	508,719.57	240,084	204,698	0.4024	304,022	18.46	16,467	16.5
2006	4,177,657.04	1,893,830	1,614,699	0.3865	2,562,958	18.69	137,116	15.5
2007	3,657,733.59	1,586,967	1,353,065	0.3699	2,304,669	18.92	121,808	14.5
2008	1,237,359.39	511,653	436,241	0.3526	801,119	19.15	41,839	13.5
2009	2,031,196.60	796,572	679,166	0.3344	1,352,031	19.37	69,786	12.5
2010	5,588,477.85	2,066,546	1,761,959	0.3153	3,826,519	19.60	195,241	11.5
2011	1,371,242.88	474,830	404,845	0.2952	966,398	19.82	48,752	10.5
2012	7,773,909.77	2,499,688	2,131,260	0.2742	5,642,650	20.04	281,505	9.5
2013	1,879,077.30	555,271	473,430	0.2519	1,405,648	20.26	69,365	8.5
2014	3,856,005.55	1,033,510	881,181	0.2285	2,974,824	20.48	145,238	7.5
2015	5,161,274.07	1,233,525	1,051,717	0.2038	4,109,557	20.70	198,557	6.5
2016	7,875,429.65	1,640,234	1,398,481	0.1776	6,476,949	20.91	309,787	5.5
2017	4,032,417.18	708,469	604,048	0.1498	3,428,369	21.11	162,383	4.5
2018	1,788,351.24	252,290	215,105	0.1203	1,573,246	21.31	73,828	3.5
2019	5,744,929.53	598,586	510,361	0.0888	5,234,568	21.49	243,539	2.5
2020	3,896,100.71	252,389	215,189	0.0552	3,680,911	21.66	169,977	1.5

Enbridge Gas Distribution

Account #: 472.00 - Distribution - Structures - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2021	80,149,541.03	1,799,691	1,534,436	0.0191	78,615,105	21.77	3,611,568	0.5
TOTAL	220,832,605.09	75,080,262	64,014,227		156,818,378		8,303,390	

COMPOSITE ANNUAL ACCRUAL RATE	3.76%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	15.68
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	18.29

Enbridge Gas Inc.

Account #: 472.31 - Distribution - Structures - Stoney Creek

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2046

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1992	1,114,233.02	745,014	401,617	0.3604	712,616	14.62	48,743	29.5
1996	264,569.14	164,748	88,811	0.3357	175,758	15.45	11,376	25.5
2010	11,256.60	4,367	2,354	0.2091	8,902	18.14	491	11.5
2011	3,046.29	1,110	598	0.1964	2,448	18.32	134	10.5
2012	24,238.48	8,223	4,433	0.1829	19,806	18.50	1,070	9.5
2013	26,834,440.69	8,391,142	4,523,435	0.1686	22,311,006	18.68	1,194,215	8.5
2014	72,795.00	20,713	11,166	0.1534	61,629	18.86	3,268	7.5
2015	15,084.11	3,840	2,070	0.1372	13,014	19.03	684	6.5
2016	3,000.00	668	360	0.1200	2,640	19.20	137	5.5
2018	3,400.00	517	279	0.0819	3,121	19.53	160	3.5
2019	76,764.68	8,655	4,666	0.0608	72,099	19.67	3,665	2.5
2021	1,239,286.80	30,390	16,383	0.0132	1,222,904	19.89	61,485	0.5
TOTAL	29,662,114.81	9,379,387	5,056,171		24,605,944		1,325,428	

COMPOSITE ANNUAL ACCRUAL RATE	4.47%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.17
COMPOSITE AVERAGE AGE (YEARS)	9.09
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	18.55

Enbridge Gas Inc.

Account #: 472.32 - Distribution - Structures - Win-Rhodes

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2046

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1961	180,426.39	163,296	94,729	0.5250	85,698	6.35	13,503	60.5
2007	129,381.63	58,466	33,916	0.2621	95,465	17.59	5,428	14.5
2008	12,068.02	5,209	3,022	0.2504	9,046	17.77	509	13.5
2009	22,631,922.21	9,288,069	5,388,051	0.2381	17,243,871	17.96	960,216	12.5
2011	65,635.22	23,910	13,870	0.2113	51,765	18.32	2,825	10.5
2013	8,062.10	2,521	1,462	0.1814	6,600	18.68	353	8.5
2015	4,463.00	1,136	659	0.1477	3,804	19.03	200	6.5
2017	65,272.23	12,307	7,139	0.1094	58,133	19.37	3,002	4.5
2018	27,450.03	4,173	2,421	0.0882	25,029	19.53	1,282	3.5
2019	65,992.08	7,441	4,316	0.0654	61,676	19.67	3,135	2.5
2021	25,873.03	634	368	0.0142	25,505	19.89	1,282	0.5
TOTAL	23,216,545.94	9,567,162	5,549,955		17,666,591		991,735	

COMPOSITE ANNUAL ACCRUAL RATE	4.27%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.24
COMPOSITE AVERAGE AGE (YEARS)	12.80
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	17.88

Enbridge Gas Inc.

Account #: 472.33 - Distribution - Structures - London Admin

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2026

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1955	199.68	191	136	0.6808	64	3.18	20	66.5
1959	5,165.84	4,896	3,492	0.6761	1,673	3.45	485	62.5
1960	1,011,560.18	957,077	682,748	0.6749	328,812	3.50	93,920	61.5
1969	386,858.53	360,578	257,225	0.6649	129,633	3.83	33,879	52.5
1970	878,076.95	816,968	582,799	0.6637	295,278	3.85	76,652	51.5
1971	5,845,067.46	5,428,354	3,872,415	0.6625	1,972,653	3.88	508,850	50.5
1975	3,368.30	3,104	2,214	0.6573	1,154	3.96	291	46.5
1980	452,780.36	412,505	294,268	0.6499	158,512	4.05	39,121	41.5
1982	2,909.02	2,637	1,881	0.6465	1,028	4.08	252	39.5
1995	16,817.65	14,496	10,341	0.6149	6,477	4.24	1,526	26.5
1997	18,229.57	15,527	11,076	0.6076	7,153	4.26	1,677	24.5
2004	318,242.92	255,112	181,989	0.5719	136,254	4.33	31,463	17.5
2006	592,897.90	463,013	330,299	0.5571	262,599	4.35	60,394	15.5
2007	1,524,698.50	1,172,436	836,378	0.5486	688,320	4.36	157,995	14.5
2008	75,814.20	57,290	40,869	0.5391	34,945	4.36	8,006	13.5
2009	87,714.83	64,981	46,355	0.5285	41,360	4.37	9,458	12.5
2010	76,186.98	55,169	39,356	0.5166	36,831	4.38	8,407	11.5
2011	3,270,478.37	2,306,368	1,645,289	0.5031	1,625,189	4.39	370,268	10.5
2012	32,272.28	22,061	15,738	0.4877	16,534	4.40	3,760	9.5
2013	84,576.51	55,709	39,741	0.4699	44,836	4.40	10,179	8.5
2014	1,057,271.39	665,667	474,866	0.4491	582,406	4.41	132,000	7.5
2015	8,913.65	5,306	3,785	0.4246	5,129	4.42	1,160	6.5
2016	5,711.46	3,165	2,257	0.3953	3,454	4.43	780	5.5
2017	64,922.75	32,703	23,329	0.3593	41,594	4.43	9,382	4.5
2018	113,400.71	49,987	35,659	0.3144	77,742	4.44	17,509	3.5
2019	86,366.66	31,083	22,173	0.2567	64,193	4.45	14,437	2.5

Enbridge Gas Inc.

Account #: 472.33 - Distribution - Structures - London Admin

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2026

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2020	473,100.18	119,223	85,050	0.1798	388,050	4.45	87,157	1.5
2021	3,296,299.21	332,491	237,188	0.0720	3,059,111	4.46	686,365	0.5
TOTAL	19,789,902.04	13,708,094	9,778,917		10,010,985		2,365,393	

COMPOSITE ANNUAL ACCRUAL RATE	11.95%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.49
COMPOSITE AVERAGE AGE (YEARS)	26.77
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	4.16

Enbridge Gas Inc.

Account #: 472.34 - Distribution - Structures - Kingston Office

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2046

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2008	173.14	75	45	0.2574	129	17.77	7	13.5
2009	15,807,650.76	6,487,409	3,868,483	0.2447	11,939,168	17.96	664,826	12.5
2010	816,665.68	316,839	188,933	0.2313	627,733	18.14	34,602	11.5
2011	13,036.61	4,749	2,832	0.2172	10,205	18.32	557	10.5
2012	17,010.23	5,770	3,441	0.2023	13,569	18.50	733	9.5
2015	5,663.00	1,442	860	0.1518	4,803	19.03	252	6.5
2016	11,740.47	2,614	1,559	0.1328	10,182	19.20	530	5.5
2017	7,351.98	1,386	827	0.1124	6,525	19.37	337	4.5
2018	12,352.19	1,878	1,120	0.0906	11,233	19.53	575	3.5
2020	26,851.89	1,891	1,128	0.0420	25,724	19.80	1,299	1.5
2021	19,080.00	468	279	0.0146	18,801	19.89	945	0.5
TOTAL	16,737,575.95	6,824,521	4,069,504		12,668,072		704,665	

COMPOSITE ANNUAL ACCRUAL RATE 4.21%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.24

COMPOSITE AVERAGE AGE (YEARS) 12.40

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 17.98

Enbridge Gas Inc.

Account #: 472.35 - Distribution - Structures - Mainway

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S0.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2023

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2008	15,525,798.74	13,983,827	3,882,332	0.2501	11,643,466	1.49	7,821,646	13.5
2011	4,400.98	3,854	1,070	0.2431	3,331	1.49	2,234	10.5
2012	36,549.22	31,589	8,770	0.2399	27,779	1.49	18,621	9.5
2014	3,924.00	3,272	909	0.2315	3,015	1.49	2,019	7.5
2015	2,872.00	2,335	648	0.2257	2,224	1.49	1,488	6.5
2016	13,798.50	10,850	3,012	0.2183	10,786	1.49	7,216	5.5
2017	28,858.18	21,660	6,013	0.2084	22,845	1.50	15,276	4.5
2018	13,142.00	9,206	2,556	0.1945	10,586	1.50	7,075	3.5
2019	292,494.03	182,954	50,793	0.1737	241,701	1.50	161,475	2.5
2020	15,458.98	7,736	2,148	0.1389	13,311	1.50	8,889	1.5
TOTAL	15,937,296.63	14,257,283	3,958,252		11,979,045		8,045,940	

COMPOSITE ANNUAL ACCRUAL RATE	50.48%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.25
COMPOSITE AVERAGE AGE (YEARS)	13.24
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	1.49

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -36%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1900	2,525,390.77	3,434,531	2,786,729	0.8114	647,803	0.00	647,803	121.5
1901	28,468.71	38,717	31,415	0.8114	7,303	0.00	7,303	120.5
1909	61.08	83	67	0.8114	16	0.00	16	112.5
1911	1,994.22	2,712	2,201	0.8114	512	0.00	512	110.5
1912	5,372.22	7,306	5,928	0.8114	1,378	0.00	1,378	109.5
1913	1,997.63	2,717	2,204	0.8114	512	0.00	512	108.5
1914	1,947.23	2,648	2,149	0.8114	499	0.00	499	107.5
1915	398.55	542	440	0.8114	102	0.00	102	106.5
1916	492.24	669	543	0.8114	126	0.00	126	105.5
1917	248.91	339	275	0.8114	64	0.00	64	104.5
1918	433.13	589	478	0.8114	111	0.00	111	103.5
1919	361.62	492	399	0.8114	93	0.00	93	102.5
1920	933.30	1,269	1,030	0.8114	239	0.00	239	101.5
1921	549.45	747	606	0.8114	141	0.00	141	100.5
1922	312.68	425	345	0.8114	80	0.00	80	99.5
1923	382.19	520	422	0.8114	98	0.00	98	98.5
1924	509.56	693	562	0.8114	131	0.00	131	97.5
1925	7.63	10	8	0.8114	2	0.00	2	96.5
1926	93.15	127	103	0.8114	24	0.00	24	95.5
1927	147.94	201	163	0.8114	38	0.00	38	94.5
1928	37,036.47	50,370	40,869	0.8114	9,500	0.00	9,500	93.5
1929	270.46	368	298	0.8114	69	0.00	69	92.5
1930	1,367.06	1,859	1,509	0.8114	351	0.00	351	91.5
1931	597.08	812	659	0.8114	153	0.00	153	90.5
1932	799.42	1,081	877	0.8069	210	0.50	210	89.5
1933	67.19	91	74	0.8063	18	0.55	18	88.5

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -36%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1934	293.99	396	322	0.8044	78	0.76	78	87.5
1935	1,448.26	1,947	1,580	0.8022	390	1.00	390	86.5
1936	582.70	781	634	0.7997	159	1.24	128	85.5
1937	1,939.37	2,592	2,103	0.7973	535	1.49	358	84.5
1938	18,335.41	24,424	19,817	0.7947	5,119	1.75	2,923	83.5
1939	2,238.77	2,972	2,412	0.7920	633	2.01	314	82.5
1940	686.07	908	736	0.7893	197	2.28	86	81.5
1941	961.16	1,267	1,028	0.7865	279	2.54	110	80.5
1942	1,598.89	2,100	1,704	0.7837	470	2.81	167	79.5
1943	474.52	621	504	0.7808	141	3.08	46	78.5
1944	64.14	84	68	0.7778	19	3.35	6	77.5
1945	1,706.25	2,216	1,798	0.7747	523	3.62	144	76.5
1946	895.82	1,159	940	0.7716	278	3.89	71	75.5
1947	332.71	429	348	0.7684	105	4.16	25	74.5
1948	790.72	1,014	823	0.7652	253	4.44	57	73.5
1949	218.37	279	226	0.7618	71	4.72	15	72.5
1950	10,122.61	12,868	10,441	0.7584	3,326	4.99	666	71.5
1951	2,523.21	3,193	2,591	0.7549	841	5.27	160	70.5
1952	3,423.94	4,312	3,499	0.7514	1,158	5.55	209	69.5
1953	6,722.68	8,425	6,836	0.7477	2,307	5.83	395	68.5
1954	1,360,971.16	1,697,149	1,377,042	0.7440	473,879	6.12	77,483	67.5
1955	393,966.77	488,763	396,575	0.7402	139,220	6.40	21,756	66.5
1956	790,277.04	975,254	791,307	0.7363	283,470	6.68	42,409	65.5
1957	1,572,724.59	1,930,285	1,566,205	0.7322	572,701	6.97	82,155	64.5
1958	2,958,567.30	3,610,842	2,929,784	0.7281	1,093,867	7.26	150,678	63.5
1959	2,923,507.31	3,547,469	2,878,365	0.7239	1,097,605	7.55	145,389	62.5

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -36%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1960	4,203,017.94	5,069,771	4,113,538	0.7196	1,602,566	7.84	204,396	61.5
1961	5,504,304.17	6,598,733	5,354,116	0.7152	2,131,738	8.13	262,093	60.5
1962	6,938,872.93	8,265,985	6,706,900	0.7107	2,729,968	8.43	323,908	59.5
1963	5,952,667.63	7,044,990	5,716,202	0.7061	2,379,426	8.72	272,737	58.5
1964	4,395,501.85	5,167,255	4,192,636	0.7014	1,785,247	9.02	197,911	57.5
1965	4,401,757.23	5,138,934	4,169,656	0.6965	1,816,733	9.32	194,984	56.5
1966	4,454,596.24	5,163,726	4,189,772	0.6916	1,868,479	9.61	194,342	55.5
1967	5,278,397.26	6,074,016	4,928,368	0.6865	2,250,252	9.91	227,041	54.5
1968	6,156,073.38	7,030,850	5,704,729	0.6814	2,667,530	10.21	261,338	53.5
1969	8,793,794.32	9,965,957	8,086,233	0.6761	3,873,328	10.50	368,812	52.5
1970	5,945,925.49	6,685,055	5,424,156	0.6708	2,662,302	10.80	246,599	51.5
1971	7,056,155.79	7,868,605	6,384,472	0.6653	3,211,900	11.09	289,657	50.5
1972	9,494,932.00	10,499,371	8,519,037	0.6597	4,394,071	11.38	386,132	49.5
1973	8,745,454.00	9,587,173	7,778,893	0.6540	4,114,925	11.67	352,639	48.5
1974	8,520,993.43	9,258,131	7,511,913	0.6482	4,076,638	11.96	340,956	47.5
1975	8,236,428.38	8,867,070	7,194,611	0.6423	4,006,931	12.24	327,303	46.5
1976	7,871,902.71	8,394,722	6,811,356	0.6362	3,894,432	12.53	310,904	45.5
1977	8,474,464.88	8,949,423	7,261,432	0.6300	4,263,840	12.81	332,901	44.5
1978	8,925,236.51	9,330,860	7,570,924	0.6237	4,567,398	13.09	348,969	43.5
1979	9,516,026.91	9,845,368	7,988,389	0.6173	4,953,408	13.37	370,584	42.5
1980	10,728,819.66	10,981,187	8,909,975	0.6106	5,681,220	13.64	416,423	41.5
1981	5,905,160.29	5,977,055	4,849,695	0.6039	3,181,323	13.92	228,585	40.5
1982	2,977,540.18	2,979,175	2,417,259	0.5969	1,632,196	14.19	115,020	39.5
1983	2,644,927.33	2,614,867	2,121,665	0.5898	1,475,436	14.46	102,022	38.5
1984	3,045,016.05	2,973,210	2,412,420	0.5825	1,728,802	14.73	117,353	37.5
1985	2,389,466.91	2,303,171	1,868,759	0.5751	1,380,916	15.00	92,061	36.5

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -36%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1986	2,634,539.55	2,505,480	2,032,910	0.5674	1,550,064	15.27	101,531	35.5
1987	2,666,190.71	2,500,308	2,028,714	0.5595	1,597,305	15.53	102,834	34.5
1988	2,808,146.33	2,595,239	2,105,739	0.5514	1,713,340	15.80	108,455	33.5
1989	3,167,397.47	2,882,935	2,339,172	0.5430	1,968,489	16.06	122,561	32.5
1990	3,272,597.28	2,931,547	2,378,615	0.5344	2,072,118	16.32	126,938	31.5
1991	3,047,962.77	2,685,053	2,178,613	0.5256	1,966,616	16.59	118,568	30.5
1992	4,160,255.29	3,601,207	2,921,967	0.5164	2,735,980	16.85	162,390	29.5
1993	5,388,113.83	4,578,951	3,715,294	0.5070	3,612,541	17.11	211,143	28.5
1994	6,039,362.88	5,033,899	4,084,432	0.4973	4,129,101	17.37	237,711	27.5
1995	8,156,115.41	6,660,739	5,404,426	0.4872	5,687,891	17.63	322,604	26.5
1996	7,278,287.86	5,816,923	4,719,767	0.4768	5,178,705	17.89	289,434	25.5
1997	3,064,373.85	2,393,800	1,942,294	0.4661	2,225,254	18.15	122,577	24.5
1998	5,010,668.70	3,820,564	3,099,950	0.4549	3,714,560	18.42	201,708	23.5
1999	5,036,046.49	3,742,404	3,036,532	0.4434	3,812,491	18.68	204,122	22.5
2000	4,397,851.29	3,179,751	2,580,004	0.4314	3,401,074	18.94	179,559	21.5
2001	5,640,785.37	3,960,764	3,213,706	0.4189	4,457,762	19.21	232,106	20.5
2002	5,933,206.55	4,037,564	3,276,021	0.4060	4,793,140	19.47	246,166	19.5
2003	5,299,077.25	3,486,730	2,829,082	0.3926	4,377,663	19.74	221,791	18.5
2004	4,568,376.31	2,898,903	2,352,127	0.3786	3,860,864	20.01	192,982	17.5
2005	10,063,946.09	6,140,614	4,982,405	0.3640	8,704,562	20.28	429,277	16.5
2006	10,856,512.94	6,348,291	5,150,911	0.3489	9,613,946	20.55	467,834	15.5
2007	10,025,595.87	5,596,807	4,541,168	0.3331	9,093,642	20.82	436,679	14.5
2008	7,960,617.67	4,224,010	3,427,300	0.3166	7,399,140	21.10	350,646	13.5
2009	3,805,622.42	1,909,410	1,549,268	0.2993	3,626,379	21.38	169,596	12.5
2010	8,078,925.95	3,809,731	3,091,161	0.2813	7,896,179	21.67	364,446	11.5
2011	6,530,861.42	2,873,722	2,331,696	0.2625	6,550,275	21.95	298,378	10.5

Enbridge Gas Distribution

Account #: 473.01 - Distribution - Services - Metal

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S1
ASL: 45
Net Salvage: -36%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2012	12,311,181.31	5,010,897	4,065,769	0.2428	12,677,438	22.24	569,954	9.5
2013	14,888,036.99	5,545,103	4,499,216	0.2222	15,748,515	22.54	698,772	8.5
2014	14,420,870.07	4,848,663	3,934,134	0.2006	15,678,249	22.84	686,535	7.5
2015	13,410,628.90	3,999,617	3,245,231	0.1779	14,993,224	23.14	647,926	6.5
2016	10,157,808.29	2,624,681	2,129,628	0.1542	11,684,992	23.45	498,327	5.5
2017	11,386,910.26	2,465,815	2,000,727	0.1292	13,485,471	23.76	567,532	4.5
2018	10,343,154.30	1,784,933	1,448,268	0.1030	12,618,422	24.08	523,960	3.5
2019	13,688,543.27	1,729,505	1,403,295	0.0754	17,213,124	24.41	705,166	2.5
2020	12,701,976.85	987,342	801,115	0.0464	16,473,574	24.74	665,754	1.5
2021	112,224,699.54	2,982,569	2,420,013	0.0159	150,205,578	25.09	5,987,563	0.5
TOTAL	549,648,294.42	330,700,801	268,325,815		479,195,865		25,654,984	

COMPOSITE ANNUAL ACCRUAL RATE	4.67%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.49
COMPOSITE AVERAGE AGE (YEARS)	23.36
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	18.61

Enbridge Gas Distribution

Account #: 473.02 - Distribution - Services - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S3
ASL: 55
Net Salvage: -32%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1900	149,768.59	197,695	131,817	0.6668	65,878	0.00	65,878	121.5
1928	1,524.06	1,968	1,312	0.6523	700	2.08	337	93.5
1958	1,524.06	1,798	1,199	0.5961	813	7.53	108	63.5
1959	2,727.43	3,201	2,135	0.5929	1,466	7.79	188	62.5
1961	2,116.75	2,456	1,638	0.5862	1,156	8.32	139	60.5
1964	47,351.00	53,903	35,941	0.5750	26,562	9.17	2,895	57.5
1965	148,347.17	167,698	111,816	0.5710	84,002	9.47	8,866	56.5
1966	156,323.18	175,425	116,968	0.5669	89,378	9.78	9,136	55.5
1967	197,396.80	219,828	146,575	0.5625	113,989	10.10	11,287	54.5
1968	815,958.94	901,421	601,041	0.5580	476,025	10.42	45,663	53.5
1969	4,064.16	4,452	2,969	0.5534	2,396	10.76	223	52.5
1970	1,563,798.64	1,698,158	1,132,283	0.5485	931,931	11.10	83,947	51.5
1971	2,450,510.49	2,636,695	1,758,072	0.5435	1,476,602	11.45	128,928	50.5
1972	96,143.32	102,457	68,315	0.5383	58,594	11.81	4,960	49.5
1973	4,916,051.66	5,186,311	3,458,082	0.5329	3,031,106	12.18	248,779	48.5
1974	4,021,050.36	4,197,553	2,798,807	0.5273	2,508,980	12.56	199,703	47.5
1975	6,120,880.56	6,319,346	4,213,557	0.5215	3,866,006	12.95	298,480	46.5
1976	6,814,251.96	6,954,337	4,636,951	0.5155	4,357,862	13.35	326,427	45.5
1977	8,258,215.90	8,326,671	5,551,983	0.5093	5,348,862	13.76	388,808	44.5
1978	10,475,227.61	10,429,158	6,953,860	0.5029	6,873,440	14.17	484,945	43.5
1979	17,737,329.70	17,426,769	11,619,665	0.4963	11,793,610	14.60	807,795	42.5
1980	22,226,662.80	21,536,927	14,360,200	0.4895	14,978,995	15.03	996,317	41.5
1981	30,598,391.49	29,222,438	19,484,676	0.4824	20,905,201	15.48	1,350,710	40.5
1982	28,850,610.66	27,139,264	18,095,676	0.4752	19,987,130	15.93	1,254,855	39.5
1983	32,788,041.96	30,359,155	20,242,605	0.4677	23,037,610	16.39	1,405,945	38.5
1984	45,051,817.04	41,029,722	27,357,431	0.4600	32,110,968	16.85	1,905,421	37.5

Enbridge Gas Distribution

Account #: 473.02 - Distribution - Services - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S3
ASL: 55
Net Salvage: -32%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1985	44,178,902.73	39,545,547	26,367,826	0.4522	31,948,326	17.33	1,844,058	36.5
1986	45,656,546.02	40,137,948	26,762,822	0.4441	33,503,819	17.80	1,881,939	35.5
1987	48,183,301.68	41,569,944	27,717,635	0.4358	35,884,323	18.28	1,962,506	34.5
1988	52,722,048.58	44,602,076	29,739,373	0.4273	39,853,731	18.77	2,123,221	33.5
1989	53,099,568.05	44,011,187	29,345,386	0.4187	40,746,044	19.26	2,115,697	32.5
1990	61,581,712.67	49,963,203	33,314,017	0.4098	47,973,843	19.75	2,429,170	31.5
1991	68,045,080.48	53,992,407	36,000,574	0.4008	53,818,932	20.24	2,659,232	30.5
1992	86,254,726.77	66,873,184	44,589,103	0.3916	69,267,136	20.73	3,342,073	29.5
1993	100,416,338.86	75,995,060	50,671,306	0.3823	81,878,261	21.21	3,860,485	28.5
1994	114,613,463.09	84,584,015	56,398,173	0.3728	94,891,599	21.69	4,375,423	27.5
1995	144,689,462.64	104,013,130	69,352,944	0.3631	121,637,147	22.16	5,489,140	26.5
1996	122,662,528.22	85,798,092	57,207,684	0.3533	104,706,853	22.62	4,628,434	25.5
1997	111,013,734.49	75,464,635	50,317,634	0.3434	96,220,496	23.07	4,170,012	24.5
1998	106,872,602.30	70,515,759	47,017,867	0.3333	94,053,968	23.51	4,000,010	23.5
1999	112,351,680.12	71,856,003	47,911,503	0.3231	100,392,715	23.94	4,193,874	22.5
2000	128,015,893.22	79,244,410	52,837,878	0.3127	116,143,101	24.35	4,770,393	21.5
2001	115,289,893.04	68,963,159	45,982,638	0.3022	106,200,021	24.74	4,293,019	20.5
2002	96,249,612.37	55,536,419	37,030,076	0.2915	90,019,412	25.11	3,585,040	19.5
2003	115,205,243.80	63,995,350	42,670,247	0.2806	109,400,675	25.46	4,296,761	18.5
2004	69,353,793.26	37,006,805	24,675,066	0.2695	66,871,941	25.79	2,592,810	17.5
2005	97,395,107.31	49,795,713	33,202,340	0.2583	95,359,202	26.10	3,653,699	16.5
2006	109,704,171.83	53,588,070	35,730,974	0.2467	109,078,533	26.39	4,134,079	15.5
2007	105,430,196.90	49,040,553	32,698,821	0.2350	106,469,039	26.65	3,995,345	14.5
2008	113,170,328.99	49,932,134	33,293,301	0.2229	116,091,533	26.89	4,317,480	13.5
2009	78,061,869.45	32,520,068	21,683,440	0.2104	81,358,228	27.11	3,001,378	12.5
2010	126,426,207.82	49,458,078	32,977,215	0.1976	133,905,380	27.30	4,904,318	11.5

Enbridge Gas Distribution

Account #: 473.02 - Distribution - Services - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life

Survivor Curve: S3

ASL: 55

Net Salvage: -32%

Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2011	115,922,136.62	42,303,992	28,207,077	0.1843	124,810,143	27.48	4,541,951	10.5
2012	138,256,592.59	46,686,847	31,129,438	0.1706	151,369,264	27.64	5,477,356	9.5
2013	138,646,957.73	42,886,509	28,595,483	0.1562	154,418,501	27.77	5,560,039	8.5
2014	132,102,041.38	36,951,028	24,637,875	0.1413	149,736,819	27.89	5,368,245	7.5
2015	150,761,600.30	37,496,733	25,001,736	0.1256	174,003,576	28.00	6,215,022	6.5
2016	148,370,557.88	32,071,163	21,384,123	0.1092	174,465,014	28.09	6,211,620	5.5
2017	142,742,100.37	25,958,399	17,308,309	0.0919	171,111,263	28.16	6,075,673	4.5
2018	151,710,925.20	22,091,000	14,729,639	0.0736	185,528,782	28.23	6,572,496	3.5
2019	180,810,000.48	19,383,598	12,924,422	0.0542	225,744,778	28.28	7,981,821	2.5
2020	164,306,151.39	10,906,909	7,272,411	0.0335	209,611,709	28.33	7,399,575	1.5
2021	345,114,099.71	7,891,126	5,261,575	0.0115	450,289,037	28.36	15,874,958	0.5
TOTAL	4,458,883,264.63	2,076,925,059	1,384,833,504		4,500,892,406		179,929,092	

COMPOSITE ANNUAL ACCRUAL RATE	4.04%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	16.26
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	24.98

Enbridge Gas Distribution

Account #: 474.00 - Distribution - Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1997	7,933,012.78	7,774,353	2,517,907	0.3174	5,415,106	0.50	5,415,106	24.5
1998	9,189,350.75	8,637,990	2,797,616	0.3044	6,391,735	1.50	4,261,157	23.5
1999	10,501,133.78	9,451,020	3,060,935	0.2915	7,440,199	2.50	2,976,079	22.5
2000	12,787,095.65	10,996,902	3,561,605	0.2785	9,225,490	3.50	2,635,854	21.5
2001	14,943,687.85	12,253,824	3,968,689	0.2656	10,974,999	4.50	2,438,889	20.5
2002	12,164,610.21	9,488,396	3,073,040	0.2526	9,091,570	5.50	1,653,013	19.5
2003	14,508,078.70	10,735,978	3,477,099	0.2397	11,030,980	6.50	1,697,074	18.5
2004	7,119,777.11	4,983,844	1,614,135	0.2267	5,505,642	7.50	734,086	17.5
2005	13,256,161.50	8,749,067	2,833,591	0.2138	10,422,571	8.50	1,226,185	16.5
2006	15,434,123.63	9,569,157	3,099,196	0.2008	12,334,927	9.50	1,298,413	15.5
2007	15,300,290.99	8,874,169	2,874,108	0.1878	12,426,183	10.50	1,183,446	14.5
2008	15,283,142.09	8,252,897	2,672,895	0.1749	12,610,248	11.50	1,096,543	13.5
2009	16,523,613.11	8,261,807	2,675,780	0.1619	13,847,833	12.50	1,107,827	12.5
2010	16,711,002.41	7,687,061	2,489,635	0.1490	14,221,367	13.50	1,053,435	11.5
2011	19,593,594.55	8,229,310	2,665,255	0.1360	16,928,339	14.50	1,167,472	10.5
2012	21,890,642.77	8,318,444	2,694,124	0.1231	19,196,519	15.50	1,238,485	9.5
2013	24,710,279.37	8,401,495	2,721,022	0.1101	21,989,258	16.50	1,332,682	8.5
2014	22,900,250.01	6,870,075	2,225,035	0.0972	20,675,215	17.50	1,181,441	7.5
2015	26,425,603.78	6,870,657	2,225,224	0.0842	24,200,380	18.50	1,308,129	6.5
2016	29,212,083.62	6,426,658	2,081,424	0.0713	27,130,659	19.50	1,391,316	5.5
2017	25,297,702.47	4,553,586	1,474,786	0.0583	23,822,916	20.50	1,162,093	4.5
2018	25,759,823.63	3,606,375	1,168,009	0.0453	24,591,814	21.50	1,143,805	3.5
2019	28,900,291.78	2,890,029	936,004	0.0324	27,964,288	22.50	1,242,857	2.5
2020	32,205,594.49	1,932,336	625,832	0.0194	31,579,762	23.50	1,343,820	1.5
2021	50,319,983.97	1,006,400	325,946	0.0065	49,994,038	24.50	2,040,573	0.5

Enbridge Gas Distribution

Account #: 474.00 - Distribution - Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	488,870,931.00	184,821,829	59,858,893		429,012,038		43,329,779	

COMPOSITE ANNUAL ACCRUAL RATE	8.86%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.12
COMPOSITE AVERAGE AGE (YEARS)	9.45
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	15.55

Enbridge Gas Distribution

Account #: 475.00 - Distribution - Mains - Envision

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2004	29,459,720.88	20,621,805	13,304,715	0.4516	16,155,006	7.50	2,154,001	17.5
2005	18,650,617.10	12,309,407	7,941,747	0.4258	10,708,870	8.50	1,259,867	16.5
2006	18,244,834.93	11,311,798	7,298,112	0.4000	10,946,723	9.50	1,152,287	15.5
2007	15,875,281.79	9,207,663	5,940,573	0.3742	9,934,709	10.50	946,163	14.5
2008	11,772,203.07	6,356,990	4,101,384	0.3484	7,670,819	11.50	667,028	13.5
2009	17,976,461.62	8,988,231	5,799,000	0.3226	12,177,461	12.50	974,197	12.5
2010	11,575,661.85	5,324,804	3,435,442	0.2968	8,140,220	13.50	602,979	11.5
2011	9,694,732.90	4,071,788	2,627,024	0.2710	7,067,709	14.50	487,428	10.5
2012	10,460,599.46	3,975,028	2,564,597	0.2452	7,896,003	15.50	509,420	9.5
2013	9,928,403.50	3,375,657	2,177,897	0.2194	7,750,507	16.50	469,728	8.5
2014	9,730,838.73	2,919,252	1,883,434	0.1936	7,847,405	17.50	448,423	7.5
2015	10,608,447.06	2,758,196	1,779,525	0.1677	8,828,922	18.50	477,239	6.5
2016	7,279,412.00	1,601,471	1,033,232	0.1419	6,246,180	19.50	320,317	5.5
2017	7,461.53	1,343	867	0.1161	6,595	20.50	322	4.5
TOTAL	181,264,676.42	92,823,432	59,887,548		121,377,128		10,469,397	

COMPOSITE ANNUAL ACCRUAL RATE	5.78%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	12.80
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	12.20

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -53%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1894	31.00	47	29	0.6165	18	0.00	18	127.5
1900	24.14	37	23	0.6165	14	0.00	14	121.5
1901	882.13	1,350	832	0.6165	518	0.00	518	120.5
1904	475.41	727	448	0.6165	279	0.00	279	117.5
1905	2,239.37	3,426	2,112	0.6165	1,314	0.00	1,314	116.5
1909	2,557.09	3,912	2,412	0.6165	1,500	0.00	1,500	112.5
1910	11,960.68	18,300	11,282	0.6165	7,018	0.00	7,018	111.5
1911	48.92	75	46	0.6165	29	0.00	29	110.5
1912	295.91	453	279	0.6165	174	0.00	174	109.5
1914	18,551.62	28,384	17,499	0.6165	10,885	0.00	10,885	107.5
1915	10.33	16	10	0.6163	6	0.00	6	106.5
1917	20.67	32	20	0.6166	12	0.00	12	104.5
1918	5,722.35	8,755	5,398	0.6165	3,358	0.00	3,358	103.5
1919	2,272.46	3,477	2,144	0.6165	1,333	0.00	1,333	102.5
1920	2,640.01	4,039	2,490	0.6165	1,549	0.00	1,549	101.5
1921	4,778.59	7,311	4,507	0.6165	2,804	0.00	2,804	100.5
1924	3,720.56	5,692	3,509	0.6165	2,183	0.00	2,183	97.5
1925	229,889.97	351,732	216,844	0.6165	134,888	0.00	134,888	96.5
1926	5,925.59	9,066	5,589	0.6165	3,477	0.00	3,477	95.5
1927	265,632.65	406,418	250,558	0.6165	155,860	0.00	155,860	94.5
1928	208,696.81	319,306	196,853	0.6165	122,453	0.00	122,453	93.5
1929	11,693.67	17,795	10,971	0.6132	6,921	0.50	6,921	92.5
1930	32,004.54	48,677	30,009	0.6128	18,958	0.55	18,958	91.5
1931	299,587.70	454,794	280,382	0.6117	177,987	0.71	177,987	90.5
1932	807.04	1,222	754	0.6103	481	0.91	481	89.5
1933	4,300.46	6,497	4,006	0.6088	2,574	1.12	2,296	88.5

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -53%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1934	4,519.92	6,812	4,199	0.6072	2,716	1.34	2,034	87.5
1935	37,493.72	56,352	34,741	0.6056	22,624	1.56	14,541	86.5
1936	49,203.14	73,740	45,461	0.6039	29,820	1.79	16,691	85.5
1937	98,402.01	147,035	90,647	0.6021	59,908	2.02	29,611	84.5
1938	49,373.63	73,548	45,343	0.6002	30,199	2.26	13,342	83.5
1939	118,259.02	175,602	108,259	0.5983	72,677	2.51	28,998	82.5
1940	46,288.16	68,514	42,239	0.5964	28,582	2.74	10,414	81.5
1941	92,337.02	136,221	83,981	0.5944	57,295	2.99	19,183	80.5
1942	3,659.02	5,380	3,317	0.5924	2,282	3.23	706	79.5
1943	10,116.06	14,821	9,137	0.5904	6,340	3.47	1,824	78.5
1944	10,235.69	14,944	9,213	0.5883	6,448	3.72	1,734	77.5
1945	3,439.76	5,004	3,085	0.5862	2,178	3.96	550	76.5
1946	76,563.83	110,971	68,414	0.5840	48,728	4.20	11,606	75.5
1947	4,547.68	6,567	4,048	0.5818	2,910	4.44	656	74.5
1948	19,057.29	27,413	16,900	0.5796	12,257	4.68	2,621	73.5
1949	5,248.90	7,521	4,637	0.5773	3,394	4.92	690	72.5
1950	33,682.36	48,065	29,632	0.5750	21,902	5.16	4,244	71.5
1951	187,806.18	266,892	164,540	0.5726	122,803	5.40	22,732	70.5
1952	96,014.69	135,860	83,758	0.5702	63,144	5.65	11,178	69.5
1953	340,239.03	479,277	295,476	0.5676	225,089	5.90	38,144	68.5
1954	294,801.17	413,327	254,818	0.5649	196,228	6.16	31,856	67.5
1955	438,970.93	612,445	377,574	0.5622	294,051	6.43	45,760	66.5
1956	1,541,821.69	2,140,084	1,319,370	0.5593	1,039,617	6.70	155,171	65.5
1957	10,729,456.30	14,812,443	9,131,926	0.5563	7,284,142	6.98	1,043,140	64.5
1958	30,571,577.15	41,965,420	25,871,836	0.5531	20,902,677	7.28	2,872,477	63.5
1959	36,689,474.62	50,061,542	30,863,125	0.5498	25,271,771	7.58	3,332,969	62.5

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -53%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1960	14,236,454.72	19,302,349	11,899,969	0.5463	9,881,807	7.90	1,250,893	61.5
1961	16,558,259.61	22,300,676	13,748,449	0.5427	11,585,688	8.23	1,407,816	60.5
1962	22,326,935.42	29,858,601	18,407,938	0.5389	15,752,273	8.57	1,837,658	59.5
1963	17,939,644.78	23,813,618	14,681,183	0.5349	12,766,473	8.93	1,430,049	58.5
1964	10,809,823.82	14,237,399	8,777,409	0.5307	7,761,622	9.30	834,987	57.5
1965	11,552,779.81	15,091,197	9,303,779	0.5264	8,371,974	9.68	865,201	56.5
1966	13,155,954.88	17,037,467	10,503,661	0.5218	9,624,950	10.07	955,853	55.5
1967	21,089,710.60	27,065,252	16,685,828	0.5171	15,581,430	10.48	1,487,483	54.5
1968	16,570,366.48	21,064,022	12,986,047	0.5122	12,366,613	10.89	1,135,321	53.5
1969	19,069,384.95	24,000,649	14,796,488	0.5071	14,379,671	11.32	1,270,163	52.5
1970	18,144,678.96	22,600,591	13,933,348	0.5019	13,828,011	11.76	1,175,866	51.5
1971	19,088,686.42	23,519,931	14,500,124	0.4965	14,705,566	12.21	1,204,586	50.5
1972	18,547,822.32	22,596,768	13,930,991	0.4909	14,447,177	12.66	1,140,752	49.5
1973	20,175,254.05	24,291,821	14,975,997	0.4852	15,892,141	13.13	1,210,370	48.5
1974	19,756,390.79	23,498,478	14,486,898	0.4793	15,740,380	13.60	1,157,241	47.5
1975	13,208,700.90	15,512,694	9,563,633	0.4732	10,645,679	14.08	756,175	46.5
1976	16,540,071.96	19,171,855	11,819,519	0.4671	13,486,791	14.56	926,372	45.5
1977	16,981,103.98	19,417,699	11,971,083	0.4608	14,010,006	15.04	931,425	44.5
1978	14,997,558.70	16,910,618	10,425,458	0.4543	12,520,807	15.53	806,452	43.5
1979	16,758,008.25	18,623,951	11,481,734	0.4478	14,158,018	16.01	884,317	42.5
1980	14,731,887.84	16,129,771	9,944,063	0.4412	12,595,725	16.49	763,737	41.5
1981	14,323,398.40	15,443,526	9,520,990	0.4345	12,393,809	16.97	730,309	40.5
1982	13,332,728.51	14,150,112	8,723,596	0.4276	11,675,479	17.44	669,313	39.5
1983	21,426,118.42	22,373,475	13,793,330	0.4208	18,988,632	17.91	1,060,178	38.5
1984	19,519,604.05	20,045,066	12,357,857	0.4138	17,507,137	18.37	952,978	37.5
1985	14,617,325.80	14,755,518	9,096,831	0.4068	13,267,677	18.82	704,903	36.5

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -53%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1986	14,706,593.66	14,586,350	8,992,538	0.3996	13,508,550	19.26	701,278	35.5
1987	31,059,637.62	30,253,051	18,651,118	0.3925	28,870,128	19.69	1,466,060	34.5
1988	19,343,553.30	18,493,864	11,401,535	0.3852	18,194,101	20.11	904,734	33.5
1989	39,248,495.27	36,812,625	22,695,119	0.3779	37,355,079	20.52	1,820,842	32.5
1990	40,677,356.96	37,407,442	23,061,826	0.3706	39,174,530	20.91	1,873,672	31.5
1991	74,523,446.21	67,152,953	41,400,043	0.3631	72,620,830	21.29	3,411,543	30.5
1992	27,487,891.82	24,254,610	14,953,056	0.3555	27,103,418	21.65	1,251,788	29.5
1993	26,003,959.82	22,452,335	13,841,948	0.3479	25,944,111	22.00	1,179,135	28.5
1994	43,932,383.15	37,088,146	22,864,979	0.3402	44,351,568	22.34	1,985,342	27.5
1995	39,499,790.13	32,575,494	20,082,912	0.3323	40,351,766	22.66	1,780,489	26.5
1996	36,452,530.54	29,339,809	18,088,100	0.3243	37,684,272	22.97	1,640,355	25.5
1997	26,797,860.90	21,028,397	12,964,084	0.3162	28,036,643	23.27	1,204,862	24.5
1998	35,597,604.06	27,201,679	16,769,935	0.3079	37,694,399	23.55	1,600,429	23.5
1999	43,830,609.47	32,572,857	20,081,286	0.2994	46,979,546	23.82	1,972,034	22.5
2000	34,427,768.62	24,845,909	15,317,595	0.2908	37,356,891	24.08	1,551,301	21.5
2001	42,096,541.71	29,454,293	18,158,680	0.2819	46,249,029	24.33	1,901,112	20.5
2002	44,496,198.90	30,129,024	18,574,654	0.2728	49,504,530	24.56	2,015,495	19.5
2003	20,542,914.89	13,433,383	8,281,730	0.2635	23,148,930	24.79	933,980	18.5
2004	25,714,395.59	16,200,992	9,987,971	0.2539	29,355,054	25.00	1,174,316	17.5
2005	40,386,777.13	24,450,354	15,073,734	0.2439	46,718,035	25.20	1,853,937	16.5
2006	54,401,891.70	31,550,256	19,450,849	0.2337	63,784,045	25.39	2,512,012	15.5
2007	86,472,776.23	47,871,548	29,512,986	0.2231	102,790,362	25.57	4,019,350	14.5
2008	50,243,100.21	26,442,415	16,301,846	0.2121	60,570,097	25.75	2,352,560	13.5
2009	46,101,813.60	22,955,116	14,151,914	0.2006	56,383,861	25.91	2,176,175	12.5
2010	28,606,114.10	13,399,289	8,260,711	0.1887	35,506,644	26.06	1,362,311	11.5
2011	56,729,296.73	24,826,745	15,305,780	0.1763	71,490,044	26.21	2,727,728	10.5

Enbridge Gas Distribution

Account #: 475.21 - Distribution - Mains - Coated & Wrapped

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -53%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2012	29,117,111.47	11,806,878	7,278,984	0.1634	37,270,197	26.34	1,414,699	9.5
2013	78,911,056.58	29,344,431	18,090,950	0.1498	102,642,967	26.47	3,877,392	8.5
2014	147,219,903.94	49,555,455	30,551,120	0.1356	194,695,333	26.59	7,322,110	7.5
2015	68,235,901.61	20,440,995	12,601,949	0.1207	91,798,981	26.70	3,438,384	6.5
2016	458,760,681.23	119,533,621	73,692,918	0.1050	628,210,925	26.80	23,444,108	5.5
2017	109,428,743.25	24,007,277	14,800,575	0.0884	152,625,402	26.88	5,677,425	4.5
2018	196,754,404.11	34,595,739	21,328,401	0.0709	279,705,838	26.96	10,376,697	3.5
2019	141,819,538.75	18,383,780	11,333,668	0.0522	205,650,226	27.01	7,614,555	2.5
2020	178,851,789.99	14,389,596	8,871,239	0.0324	264,772,000	27.03	9,797,258	1.5
2021	363,811,882.15	10,140,110	6,251,415	0.0112	550,380,764	26.95	20,424,529	0.5
TOTAL	3,320,418,328.48	1,705,357,259	1,051,359,036		4,028,881,007		176,679,585	

COMPOSITE ANNUAL ACCRUAL RATE	5.32%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	16.91
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	23.56

Enbridge Gas Distribution

Account #: 475.30 - Distribution - Mains - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -51%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1958	807.98	1,100	609	0.4989	611	6.94	88	63.5
1967	46.86	59	33	0.4604	38	11.00	3	54.5
1968	156,584.48	194,441	107,600	0.4551	128,842	11.56	11,149	53.5
1970	9,247.98	11,199	6,197	0.4438	7,767	12.72	611	51.5
1971	138,390.05	165,391	91,525	0.4380	117,444	13.31	8,826	50.5
1972	343,888.32	405,436	224,362	0.4321	294,910	13.90	21,219	49.5
1973	2,440,656.75	2,837,630	1,570,300	0.4261	2,115,092	14.49	145,972	48.5
1974	4,605,656.70	5,278,650	2,921,122	0.4200	4,033,420	15.08	267,459	47.5
1975	4,675,574.02	5,280,604	2,922,203	0.4139	4,137,914	15.67	264,065	46.5
1976	6,423,773.65	7,146,619	3,954,826	0.4077	5,745,072	16.26	353,416	45.5
1977	8,224,377.01	9,009,687	4,985,819	0.4015	7,432,991	16.84	441,439	44.5
1978	11,301,973.90	12,186,885	6,744,030	0.3952	10,321,951	17.42	592,688	43.5
1979	18,397,967.81	19,520,347	10,802,252	0.3888	16,978,679	17.99	944,043	42.5
1980	34,491,240.57	35,995,257	19,919,208	0.3825	32,162,566	18.55	1,734,147	41.5
1981	25,464,108.56	26,129,170	14,459,471	0.3761	23,991,333	19.10	1,256,194	40.5
1982	25,607,426.94	25,827,244	14,292,390	0.3696	24,374,825	19.64	1,241,248	39.5
1983	25,357,560.44	25,129,291	13,906,154	0.3632	24,383,763	20.16	1,209,327	38.5
1984	31,785,627.19	30,939,308	17,121,325	0.3567	30,874,972	20.67	1,493,425	37.5
1985	25,074,148.58	23,964,473	13,261,561	0.3503	24,600,403	21.17	1,162,200	36.5
1986	25,595,652.42	24,011,065	13,287,345	0.3438	25,362,090	21.64	1,171,859	35.5
1987	31,498,975.80	28,992,220	16,043,838	0.3373	31,519,616	22.10	1,426,273	34.5
1988	29,513,727.35	26,643,099	14,743,871	0.3308	29,821,857	22.54	1,323,344	33.5
1989	43,234,172.45	38,262,848	21,174,057	0.3243	44,109,544	22.95	1,921,892	32.5
1990	33,573,751.34	29,116,396	16,112,555	0.3178	34,583,810	23.35	1,481,321	31.5
1991	44,329,393.44	37,653,205	20,836,690	0.3113	46,100,694	23.72	1,943,464	30.5
1992	42,316,315.53	35,183,708	19,470,109	0.3047	44,427,527	24.08	1,845,352	29.5

Enbridge Gas Distribution

Account #: 475.30 - Distribution - Mains - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -51%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1993	45,660,367.03	37,138,096	20,551,637	0.2981	48,395,517	24.41	1,982,573	28.5
1994	71,406,330.17	56,775,179	31,418,489	0.2914	76,405,069	24.73	3,090,054	27.5
1995	84,083,522.93	65,301,573	36,136,861	0.2846	90,829,258	25.02	3,629,677	26.5
1996	80,697,145.79	61,160,299	33,845,145	0.2778	88,007,545	25.30	3,477,884	25.5
1997	81,189,401.12	59,989,442	33,197,212	0.2708	89,398,784	25.57	3,496,396	24.5
1998	87,155,125.69	62,710,332	34,702,909	0.2637	96,901,331	25.82	3,753,359	23.5
1999	88,130,303.58	61,672,452	34,128,563	0.2565	98,948,196	26.05	3,798,325	22.5
2000	83,554,050.58	56,785,937	31,424,442	0.2491	94,742,174	26.27	3,606,676	21.5
2001	86,814,041.80	57,210,810	31,659,560	0.2415	99,429,643	26.47	3,755,975	20.5
2002	70,173,181.01	44,760,603	24,769,812	0.2338	81,191,691	26.66	3,045,195	19.5
2003	69,467,695.34	42,802,373	23,686,158	0.2258	81,210,061	26.84	3,025,920	18.5
2004	49,483,656.96	29,383,731	16,260,493	0.2176	58,459,829	27.00	2,165,098	17.5
2005	71,346,819.36	40,722,914	22,535,419	0.2092	85,198,279	27.15	3,137,914	16.5
2006	130,542,562.61	71,404,743	39,514,259	0.2005	157,605,011	27.29	5,775,371	15.5
2007	117,078,848.28	61,157,168	33,843,413	0.1914	142,945,648	27.42	5,214,020	14.5
2008	100,171,111.97	49,766,729	27,540,123	0.1821	123,718,256	27.53	4,493,749	13.5
2009	111,486,378.79	52,429,035	29,013,401	0.1723	139,331,031	27.64	5,041,602	12.5
2010	101,185,681.78	44,787,491	24,784,692	0.1622	128,005,688	27.73	4,615,862	11.5
2011	79,567,412.20	32,922,894	18,219,011	0.1516	101,927,782	27.82	3,664,087	10.5
2012	92,279,144.86	35,398,203	19,588,808	0.1406	119,752,701	27.90	4,292,857	9.5
2013	97,943,602.25	34,473,635	19,077,166	0.1290	128,817,673	27.97	4,606,270	8.5
2014	94,463,784.26	30,111,242	16,663,087	0.1168	125,977,227	28.03	4,494,638	7.5
2015	88,837,469.15	25,212,175	13,952,020	0.1040	120,192,558	28.08	4,279,741	6.5
2016	118,935,839.98	29,368,314	16,251,962	0.0905	163,341,156	28.13	5,805,910	5.5
2017	134,545,796.71	27,977,795	15,482,470	0.0762	187,681,683	28.18	6,660,741	4.5
2018	123,856,432.62	20,639,200	11,421,408	0.0611	175,601,806	28.22	6,223,607	3.5

Enbridge Gas Distribution

Account #: 475.30 - Distribution - Mains - Plastic

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R4
ASL: 60
Net Salvage: -51%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2019	121,499,902.69	14,916,655	8,254,642	0.0450	175,210,211	28.25	6,202,499	2.5
2020	143,054,172.92	10,881,986	6,021,919	0.0279	209,989,882	28.28	7,426,539	1.5
2021	380,935,199.57	9,988,272	5,527,352	0.0096	569,684,799	28.29	20,134,205	0.5
TOTAL	3,480,106,028.12	1,677,734,610	928,431,883		4,326,528,219		163,157,767	

COMPOSITE ANNUAL ACCRUAL RATE 4.69%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.27

COMPOSITE AVERAGE AGE (YEARS) 15.18

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 26.48

Enbridge Gas Distribution

Account #: 476.00 - Distribution - Company NGV Compressor Stations
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 17
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	942,259.45	919,888	942,259	1.0000	0	0.74	0	30.5
1994	330,634.49	316,502	330,634	1.0000	0	1.23	0	27.5
1996	29,028.16	27,345	29,028	1.0000	0	1.57	0	25.5
1997	296,027.20	276,337	296,027	1.0000	0	1.75	0	24.5
1998	88,211.29	81,516	88,211	1.0000	0	1.93	0	23.5
2001	364,723.75	324,297	364,724	1.0000	0	2.56	0	20.5
2005	235,141.40	192,391	235,141	1.0000	0	3.67	0	16.5
2010	354,709.77	235,433	354,710	1.0000	0	5.83	0	11.5
2013	268,244.94	140,555	268,245	1.0000	0	7.72	0	8.5
2014	247,673.77	116,333	247,674	1.0000	0	8.47	0	7.5
2015	156,531.87	64,528	156,532	1.0000	0	9.27	0	6.5
2016	200,621.12	70,649	200,621	1.0000	0	10.12	0	5.5
2017	711,674.46	206,434	537,056	0.7546	174,618	11.01	15,855	4.5
2018	2,151,976.17	487,597	664,553	0.3088	1,487,423	11.95	124,502	3.5
2019	1,374,242.78	222,938	303,845	0.2211	1,070,397	12.91	82,908	2.5
2020	771,588.19	75,178	102,461	0.1328	669,127	13.90	48,155	1.5
2021	1,355,413.93	44,032	60,012	0.0443	1,295,402	14.89	86,992	0.5
TOTAL	9,878,702.74	3,801,953	5,181,735		4,696,968		358,412	

COMPOSITE ANNUAL ACCRUAL RATE 3.63%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.52

COMPOSITE AVERAGE AGE (YEARS) 8.66

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 9.67

Enbridge Gas Distribution

Account #: 477.00 - Distribution - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -10%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1959	196,007.64	205,281	196,008	0.9091	19,601	3.14	6,234	62.5
1969	1,232,838.22	1,219,862	1,232,838	0.9091	123,284	5.86	21,023	52.5
1970	203,403.32	199,873	203,403	0.9091	20,340	6.15	3,307	51.5
1971	581,568.69	567,335	581,569	0.9091	58,157	6.44	9,025	50.5
1972	910,009.11	880,979	910,009	0.9091	91,001	6.74	13,493	49.5
1973	339,752.34	326,280	339,752	0.9091	33,975	7.05	4,817	48.5
1974	665,094.42	633,330	665,094	0.9091	66,509	7.37	9,024	47.5
1975	750,684.33	708,472	750,684	0.9091	75,068	7.70	9,752	46.5
1976	926,082.87	865,801	926,083	0.9091	92,608	8.03	11,526	45.5
1977	1,506,679.30	1,394,647	1,506,679	0.9091	150,668	8.38	17,975	44.5
1978	1,409,834.99	1,291,359	1,409,835	0.9091	140,983	8.74	16,131	43.5
1979	1,397,378.07	1,265,838	1,397,378	0.9091	139,738	9.11	15,342	42.5
1980	1,645,791.15	1,473,548	1,645,791	0.9091	164,579	9.49	17,350	41.5
1981	17,279,686.38	15,282,079	17,279,686	0.9091	1,727,969	9.87	175,013	40.5
1982	2,887,513.76	2,520,865	2,887,514	0.9091	288,751	10.27	28,117	39.5
1983	2,127,312.40	1,832,097	2,127,312	0.9091	212,731	10.67	19,930	38.5
1984	4,927,795.71	4,183,740	4,927,796	0.9091	492,780	11.09	44,450	37.5
1985	3,919,158.61	3,277,876	3,919,159	0.9091	391,916	11.50	34,065	36.5
1986	3,568,962.63	2,938,403	3,568,963	0.9091	356,896	11.93	29,916	35.5
1987	6,689,897.31	5,417,879	6,689,897	0.9091	668,990	12.36	54,126	34.5
1988	6,139,081.48	4,886,659	6,139,081	0.9091	613,908	12.79	47,982	33.5
1989	7,046,752.77	5,508,607	7,046,753	0.9091	704,675	13.23	53,254	32.5
1990	12,245,184.50	9,392,763	12,245,185	0.9091	1,224,518	13.67	89,560	31.5
1991	10,773,448.73	8,101,654	10,773,449	0.9091	1,077,345	14.11	76,330	30.5
1992	7,962,265.90	5,864,688	7,962,266	0.9091	796,227	14.56	54,700	29.5
1993	10,823,467.72	7,800,875	10,823,468	0.9091	1,082,347	15.00	72,170	28.5

Enbridge Gas Distribution

Account #: 477.00 - Distribution - Measuring and Regulating Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -10%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1994	14,079,112.59	9,919,237	14,079,113	0.9091	1,407,911	15.44	91,209	27.5
1995	15,281,977.36	10,513,355	10,998,130	0.6543	5,812,045	15.87	366,187	26.5
1996	18,447,602.03	12,378,399	11,387,337	0.5612	8,905,026	16.30	546,217	25.5
1997	13,222,441.97	8,643,104	7,951,104	0.5467	6,593,582	16.73	394,146	24.5
1998	22,509,318.46	14,314,818	13,168,718	0.5318	11,591,532	17.15	675,978	23.5
1999	26,109,355.04	16,131,370	14,839,830	0.5167	13,880,461	17.56	790,504	22.5
2000	27,857,152.92	16,695,367	15,358,671	0.5012	15,284,198	17.96	850,949	21.5
2001	14,352,001.12	8,329,611	7,662,710	0.4854	8,124,491	18.35	442,658	20.5
2002	12,545,874.76	7,038,173	6,474,669	0.4692	7,325,793	18.74	391,008	19.5
2003	15,114,471.31	8,179,044	7,524,198	0.4526	9,101,721	19.11	476,385	18.5
2004	19,955,293.97	10,392,381	9,560,327	0.4355	12,390,497	19.46	636,600	17.5
2005	17,661,309.06	8,828,664	8,121,807	0.4181	11,305,633	19.81	570,756	16.5
2006	21,974,682.05	10,512,888	9,671,185	0.4001	14,500,965	20.14	720,046	15.5
2007	21,410,214.52	9,769,448	8,987,268	0.3816	14,563,968	20.46	711,994	14.5
2008	26,093,263.92	11,311,382	10,405,749	0.3625	18,296,842	20.76	881,512	13.5
2009	25,951,245.67	10,638,533	9,786,771	0.3428	18,759,599	21.04	891,563	12.5
2010	16,637,831.58	6,414,871	5,901,272	0.3224	12,400,343	21.31	581,917	11.5
2011	22,106,903.59	7,964,302	7,326,649	0.3013	16,990,945	21.56	788,081	10.5
2012	28,867,818.40	9,640,687	8,868,816	0.2793	22,885,784	21.79	1,050,230	9.5
2013	27,156,145.75	8,324,461	7,657,973	0.2564	22,213,788	22.00	1,009,641	8.5
2014	36,553,439.27	10,157,555	9,344,302	0.2324	30,864,481	22.19	1,390,992	7.5
2015	41,726,961.12	10,341,674	9,513,680	0.2073	36,385,978	22.35	1,628,075	6.5
2016	122,074,437.89	26,398,658	24,285,079	0.1809	109,996,802	22.48	4,893,790	5.5
2017	51,923,735.00	9,497,242	8,736,856	0.1530	48,379,252	22.56	2,144,199	4.5
2018	27,334,249.67	4,033,500	3,710,562	0.1234	26,357,112	22.59	1,166,724	3.5
2019	28,257,924.31	3,105,015	2,856,415	0.0919	28,227,301	22.53	1,253,042	2.5

Enbridge Gas Distribution

Account #: 477.00 - Distribution - Measuring and Regulating Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -10%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2020	64,233,414.65	4,455,359	4,098,645	0.0580	66,558,111	22.29	2,986,244	1.5
2021	63,362,267.28	1,580,487	1,453,947	0.0209	68,244,547	21.55	3,166,845	0.5
TOTAL	950,956,097.61	363,550,373	367,887,432		678,164,276		32,432,104	

COMPOSITE ANNUAL ACCRUAL RATE	3.41%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.39
COMPOSITE AVERAGE AGE (YEARS)	13.23
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	19.87

Enbridge Gas Inc.

Account #: 477.01 - Distribution - Customer M&R Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1964	1,195.15	1,184	1,059	0.8858	137	0.56	137	57.5
1968	7,264.20	7,081	6,333	0.8719	931	1.38	673	53.5
1970	51,709.38	49,911	44,640	0.8633	7,069	1.86	3,810	51.5
1971	4,739.48	4,551	4,070	0.8588	669	2.10	319	50.5
1972	9,572.52	9,141	8,176	0.8541	1,397	2.34	598	49.5
1975	422.87	397	355	0.8393	68	3.05	22	46.5
1976	64,825.71	60,448	54,064	0.8340	10,761	3.30	3,266	45.5
1977	51,919.59	48,096	43,017	0.8285	8,903	3.54	2,517	44.5
1978	130,934.35	120,446	107,726	0.8227	23,209	3.79	6,127	43.5
1979	601,286.63	548,990	491,011	0.8166	110,276	4.05	27,238	42.5
1980	509,213.82	461,183	412,478	0.8100	96,736	4.32	22,382	41.5
1981	5,356,566.40	4,809,048	4,301,165	0.8030	1,055,402	4.61	228,888	40.5
1982	515,597.60	458,515	410,091	0.7954	105,507	4.92	21,455	39.5
1983	393,928.62	346,708	310,093	0.7872	83,836	5.24	15,988	38.5
1984	736,121.88	640,618	572,962	0.7784	163,160	5.59	29,185	37.5
1985	1,146,838.66	985,865	881,747	0.7689	265,091	5.96	44,480	36.5
1986	1,513,563.83	1,283,847	1,148,260	0.7586	365,303	6.35	57,510	35.5
1987	9,491,461.63	7,934,985	7,096,972	0.7477	2,394,490	6.77	353,832	34.5
1988	362,409.54	298,255	266,756	0.7361	95,653	7.21	13,274	33.5
1989	418,696.07	338,773	302,995	0.7237	115,701	7.67	15,090	32.5
1990	613,558.37	487,426	435,949	0.7105	177,609	8.15	21,789	31.5
1991	1,123,804.07	875,337	782,893	0.6966	340,911	8.66	39,378	30.5
1992	1,682,033.42	1,282,690	1,147,225	0.6820	534,808	9.18	58,231	29.5
1993	2,026,271.87	1,510,539	1,351,011	0.6667	675,261	9.73	69,396	28.5
1994	667,459.17	485,652	434,362	0.6508	233,097	10.29	22,642	27.5
1995	4,080,318.58	2,893,031	2,587,498	0.6341	1,492,820	10.88	137,265	26.5

Enbridge Gas Inc.

Account #: 477.01 - Distribution - Customer M&R Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1996	6,561,650.27	4,525,785	4,047,817	0.6169	2,513,833	11.47	219,150	25.5
1997	752,765.01	504,189	450,941	0.5990	301,824	12.08	24,987	24.5
1998	1,208,244.49	784,382	701,543	0.5806	506,701	12.70	39,901	23.5
1999	1,355,641.34	851,350	761,439	0.5617	594,202	13.33	44,584	22.5
2000	1,081,496.63	655,663	586,418	0.5422	495,078	13.96	35,455	21.5
2001	708,667.59	413,839	370,134	0.5223	338,534	14.60	23,180	20.5
2002	2,700,373.23	1,515,372	1,355,334	0.5019	1,345,039	15.25	88,207	19.5
2003	3,285,837.20	1,767,418	1,580,761	0.4811	1,705,076	15.89	107,280	18.5
2004	2,677,178.61	1,376,458	1,231,090	0.4598	1,446,088	16.54	87,445	17.5
2005	1,436,766.50	703,941	629,598	0.4382	807,169	17.18	46,991	16.5
2006	7,709,627.46	3,587,469	3,208,597	0.4162	4,501,031	17.81	252,722	15.5
2007	1,951,520.01	859,212	768,471	0.3938	1,183,049	18.43	64,179	14.5
2008	10,043,243.77	4,166,061	3,726,084	0.3710	6,317,160	19.04	331,699	13.5
2009	8,335,343.56	3,241,731	2,899,372	0.3478	5,435,972	19.64	276,769	12.5
2010	500,125.32	181,325	162,176	0.3243	337,950	20.22	16,715	11.5
2011	1,708,429.37	573,543	512,971	0.3003	1,195,458	20.78	57,539	10.5
2012	1,514,115.54	466,830	417,528	0.2758	1,096,588	21.31	51,453	9.5
2013	3,015,275.30	845,223	755,959	0.2507	2,259,316	21.82	103,528	8.5
2014	4,845,360.23	1,219,165	1,090,409	0.2250	3,754,951	22.31	168,327	7.5
2015	1,925,850.02	427,771	382,594	0.1987	1,543,256	22.76	67,796	6.5
2016	2,275,352.09	436,209	390,141	0.1715	1,885,211	23.19	81,297	5.5
2017	10,255,924.80	1,643,443	1,469,879	0.1433	8,786,045	23.58	372,570	4.5
2018	4,380,781.50	558,791	499,777	0.1141	3,881,005	23.94	162,120	3.5
2019	3,059,725.72	285,927	255,730	0.0836	2,803,996	24.25	115,616	2.5
2020	3,626,193.86	209,181	187,089	0.0516	3,439,105	24.50	140,356	1.5
2021	25,249,778.31	502,810	449,708	0.0178	24,800,070	24.61	1,007,778	0.5

Enbridge Gas Inc.

Account #: 477.01 - Distribution - Customer M&R Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R3
ASL: 35
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	143,726,981.14	58,245,804	52,094,469		91,632,512		5,183,135	

COMPOSITE ANNUAL ACCRUAL RATE	3.61%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.36
COMPOSITE AVERAGE AGE (YEARS)	14.92
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	17.67

Enbridge Gas Distribution

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 15
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1965	11,515.80	11,516	9,536	0.8280	1,980	0.00	1,980	56.5
1966	15,947.54	15,948	13,205	0.8280	2,742	0.00	2,742	55.5
1967	19,957.18	19,957	16,525	0.8280	3,432	0.00	3,432	54.5
1968	26,185.85	26,186	21,683	0.8280	4,503	0.00	4,503	53.5
1969	110,897.73	110,898	91,828	0.8280	19,070	0.00	19,070	52.5
1970	128,947.68	128,948	106,774	0.8280	22,174	0.00	22,174	51.5
1971	331,247.66	331,248	274,286	0.8280	56,962	0.00	56,962	50.5
1972	290,388.40	290,388	240,453	0.8280	49,936	0.00	49,936	49.5
1973	368,623.61	368,624	305,235	0.8280	63,389	0.00	63,389	48.5
1974	399,773.17	399,773	331,028	0.8280	68,746	0.00	68,746	47.5
1975	631,638.90	631,639	523,021	0.8280	108,618	0.00	108,618	46.5
1976	887,779.02	887,779	735,115	0.8280	152,664	0.00	152,664	45.5
1977	433,242.13	433,242	358,741	0.8280	74,501	0.00	74,501	44.5
1978	832,856.58	832,857	689,637	0.8280	143,219	0.00	143,219	43.5
1979	1,624,770.67	1,624,771	1,345,373	0.8280	279,398	0.00	279,398	42.5
1980	3,524,617.31	3,524,617	2,918,519	0.8280	606,098	0.00	606,098	41.5
1981	1,453,800.76	1,453,801	1,203,803	0.8280	249,998	0.00	249,998	40.5
1982	3,230,750.81	3,230,751	2,675,186	0.8280	555,565	0.00	555,565	39.5
1983	1,497,070.07	1,497,070	1,239,632	0.8280	257,438	0.00	257,438	38.5
1984	2,207,839.21	2,207,839	1,828,176	0.8280	379,663	0.00	379,663	37.5
1985	2,592,647.22	2,592,647	2,146,812	0.8280	445,835	0.00	445,835	36.5
1986	3,679,976.86	3,679,977	3,047,163	0.8280	632,814	0.00	632,814	35.5
1987	6,605,247.95	6,605,248	5,469,400	0.8280	1,135,848	0.00	1,135,848	34.5
1988	9,255,723.22	9,255,723	7,664,096	0.8280	1,591,628	0.00	1,591,628	33.5
1989	4,569,271.82	4,569,272	3,783,533	0.8280	785,739	0.00	785,739	32.5
1990	5,788,779.87	5,788,780	4,793,333	0.8280	995,447	0.00	995,447	31.5

Enbridge Gas Distribution

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 15
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	7,174,653.94	7,174,654	5,940,890	0.8280	1,233,764	0.00	1,233,764	30.5
1992	7,640,147.03	7,640,147	6,326,336	0.8280	1,313,811	0.00	1,313,811	29.5
1993	8,874,564.78	8,721,555	7,221,784	0.8138	1,652,781	0.50	1,652,781	28.5
1994	11,920,608.64	11,667,709	9,661,312	0.8105	2,259,296	0.60	2,259,296	27.5
1995	21,968,294.96	21,373,171	17,697,809	0.8056	4,270,486	0.74	4,270,486	26.5
1996	13,715,285.30	13,249,716	10,971,275	0.7999	2,744,010	0.90	2,744,010	25.5
1997	13,768,080.78	13,198,201	10,928,619	0.7938	2,839,462	1.06	2,684,116	24.5
1998	16,411,566.76	15,598,574	12,916,220	0.7870	3,495,347	1.22	2,853,779	23.5
1999	12,007,631.53	11,306,250	9,362,011	0.7797	2,645,621	1.40	1,895,436	22.5
2000	16,649,433.65	15,515,651	12,847,557	0.7717	3,801,877	1.57	2,419,912	21.5
2001	15,518,144.90	14,293,468	11,835,543	0.7627	3,682,602	1.76	2,096,607	20.5
2002	15,851,999.51	14,407,899	11,930,296	0.7526	3,921,704	1.95	2,006,520	19.5
2003	18,457,550.88	16,521,783	13,680,673	0.7412	4,776,878	2.17	2,203,819	18.5
2004	10,414,273.80	9,157,941	7,583,128	0.7281	2,831,146	2.40	1,179,281	17.5
2005	23,798,080.35	20,496,859	16,972,189	0.7132	6,825,891	2.66	2,568,550	16.5
2006	27,435,896.11	23,059,564	19,094,208	0.6960	8,341,688	2.94	2,835,718	15.5
2007	26,144,359.34	21,347,445	17,676,507	0.6761	8,467,852	3.26	2,598,898	14.5
2008	30,673,221.79	24,198,673	20,037,434	0.6533	10,635,788	3.61	2,944,543	13.5
2009	31,630,017.27	23,949,487	19,831,098	0.6270	11,798,919	4.01	2,943,318	12.5
2010	34,775,468.83	25,067,694	20,757,017	0.5969	14,018,452	4.45	3,147,726	11.5
2011	40,398,219.52	27,451,829	22,731,173	0.5627	17,667,047	4.95	3,567,773	10.5
2012	41,599,497.81	26,329,806	21,802,095	0.5241	19,797,403	5.51	3,593,371	9.5
2013	37,834,256.29	21,982,769	18,202,580	0.4811	19,631,676	6.13	3,202,955	8.5
2014	43,308,908.70	22,693,214	18,790,856	0.4339	24,518,053	6.81	3,598,510	7.5
2015	60,792,567.30	28,099,837	23,267,748	0.3827	37,524,819	7.56	4,962,012	6.5
2016	47,739,140.49	18,927,180	15,672,435	0.3283	32,066,706	8.37	3,830,053	5.5

Enbridge Gas Distribution

Account #: 478.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: S2.5
ASL: 15
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	56,152,165.09	18,393,237	15,230,310	0.2712	40,921,856	9.24	4,429,772	4.5
2018	52,904,201.19	13,563,364	11,230,988	0.2123	41,673,213	10.15	4,104,996	3.5
2019	51,912,471.49	9,539,909	7,899,412	0.1522	44,013,059	11.10	3,963,703	2.5
2020	70,913,720.74	7,830,720	6,484,138	0.0914	64,429,583	12.08	5,331,917	1.5
2021	102,006,967.90	3,756,064	3,110,166	0.0305	98,896,802	13.08	7,561,512	0.5
TOTAL	1,020,910,893.69	567,033,865	469,525,898		551,384,996		104,686,353	

COMPOSITE ANNUAL ACCRUAL RATE	10.25%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.46
COMPOSITE AVERAGE AGE (YEARS)	11.32
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	6.37

Enbridge Gas Inc.

Account #: 482.00 - General Plant - Structures and Improvements - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1995	2,833,236.13	1,745,046	2,833,236	1.0000	0	16.53	0	26.5
1999	49,855.62	27,753	49,856	1.0000	0	17.92	0	22.5
2002	9,587.48	4,873	9,587	1.0000	0	18.87	0	19.5
2004	920.38	436	920	1.0000	0	19.44	0	17.5
2007	90,731.01	37,924	90,731	1.0000	0	20.19	0	14.5
2008	29,169.23	11,613	29,169	1.0000	0	20.41	0	13.5
2009	19,247.27	7,267	19,247	1.0000	0	20.61	0	12.5
2010	6,240.06	2,223	6,240	1.0000	0	20.79	0	11.5
2011	75,469.15	25,199	75,469	1.0000	0	20.95	0	10.5
2012	637,765.77	198,107	637,766	1.0000	0	21.08	0	9.5
2013	4,275,021.21	1,223,739	3,948,290	0.9236	326,731	21.19	15,416	8.5
2014	87,416.91	22,784	53,423	0.6111	33,994	21.28	1,598	7.5
2015	958,501.59	223,937	525,071	0.5478	433,431	21.32	20,328	6.5
2016	345,540.19	70,849	166,122	0.4808	179,418	21.32	8,414	5.5
2019	15,310.37	1,639	3,842	0.2509	11,468	20.86	550	2.5
2021	3,821,559.62	97,512	228,639	0.0598	3,592,921	19.10	188,157	0.5
TOTAL	13,255,571.99	3,700,900	8,677,610		4,577,962		234,463	

COMPOSITE ANNUAL ACCRUAL RATE	1.77%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.65
COMPOSITE AVERAGE AGE (YEARS)	9.98
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	19.57

Enbridge Gas Inc.

Account #: 482.01 - General Plant - Structures and Improvements - VPC

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2033

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1959	150,580.47	140,134	103,473	0.6872	47,107	4.66	10,111	62.5
1962	3,529,701.59	3,243,283	2,394,792	0.6785	1,134,910	5.25	215,987	59.5
1976	4,807,417.62	4,120,930	3,042,833	0.6329	1,764,584	7.58	232,806	45.5
1978	296.94	251	186	0.6252	111	7.87	14	43.5
1980	7,324.75	6,121	4,520	0.6171	2,805	8.16	344	41.5
1981	5,383.58	4,468	3,299	0.6128	2,084	8.30	251	40.5
1987	366,065.00	289,937	214,085	0.5848	151,980	9.06	16,777	34.5
1989	13,975.00	10,871	8,027	0.5744	5,948	9.28	641	32.5
2002	237,775.83	155,569	114,870	0.4831	122,906	10.30	11,928	19.5
2003	309,854.06	198,660	146,688	0.4734	163,166	10.35	15,758	18.5
2004	1,209,342.07	758,504	560,068	0.4631	649,274	10.40	62,420	17.5
2005	1,702,239.30	1,042,386	769,682	0.4522	932,557	10.44	89,284	16.5
2006	1,033,177.89	616,298	455,065	0.4405	578,113	10.48	55,139	15.5
2007	2,161,445.58	1,252,595	924,897	0.4279	1,236,548	10.52	117,533	14.5
2008	745,098.01	418,184	308,781	0.4144	436,317	10.55	41,343	13.5
2009	1,040,590.97	563,510	416,087	0.3999	624,504	10.58	59,011	12.5
2010	2,744,982.36	1,427,837	1,054,294	0.3841	1,690,689	10.61	159,372	11.5
2011	1,406,482.15	698,899	516,056	0.3669	890,426	10.63	83,762	10.5
2012	1,658,682.89	782,062	577,463	0.3481	1,081,220	10.65	101,536	9.5
2013	2,726,178.77	1,209,254	892,895	0.3275	1,833,284	10.66	171,935	8.5
2014	602,253.48	248,565	183,536	0.3047	418,717	10.67	39,235	7.5
2015	9,228,242.69	3,492,397	2,578,734	0.2794	6,649,509	10.68	622,877	6.5
2016	4,074,294.65	1,385,676	1,023,162	0.2511	3,051,132	10.67	285,911	5.5
2017	13,490,551.78	4,005,123	2,957,323	0.2192	10,533,229	10.66	988,343	4.5
2018	3,622.63	897	663	0.1829	2,960	10.63	279	3.5
2020	207,794.29	26,070	19,250	0.0926	188,544	10.46	18,032	1.5

Enbridge Gas Inc.

Account #: 482.01 - General Plant - Structures and Improvements - VPC
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2033

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
TOTAL	53,463,354.35	26,098,479	19,270,729		34,192,626		3,400,629	

COMPOSITE ANNUAL ACCRUAL RATE	6.36%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.36
COMPOSITE AVERAGE AGE (YEARS)	15.24
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	9.97

Enbridge Gas Inc.

Account #: 482.04 - General Plant - Structures and Improvements - Thorold

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2022

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2002	73,458.65	71,622	31,416	0.4277	42,043	0.50	42,043	19.5
2003	155,088.99	151,008	66,237	0.4271	88,852	0.50	88,852	18.5
2004	543,366.08	528,273	231,718	0.4264	311,649	0.50	311,649	17.5
2005	85,913.98	83,387	36,576	0.4257	49,338	0.50	49,338	16.5
2006	224,274.90	217,266	95,300	0.4249	128,975	0.50	128,975	15.5
2007	533,394.60	515,615	226,165	0.4240	307,229	0.50	307,229	14.5
2008	187,214.72	180,528	79,186	0.4230	108,029	0.50	108,029	13.5
2009	151,221.70	145,405	63,780	0.4218	87,442	0.50	87,442	12.5
2010	179,072.00	171,611	75,274	0.4204	103,798	0.50	103,798	11.5
2011	752,683.51	718,471	315,145	0.4187	437,539	0.50	437,539	10.5
2012	275,143.36	261,386	114,652	0.4167	160,491	0.50	160,491	9.5
2013	1,628,079.52	1,537,631	674,455	0.4143	953,625	0.50	953,625	8.5
2014	483,576.03	453,353	198,855	0.4112	284,721	0.50	284,721	7.5
2015	618,715.01	574,521	252,004	0.4073	366,711	0.50	366,711	6.5
2016	9,224,708.22	8,455,983	3,709,069	0.4021	5,515,640	0.50	5,515,640	5.5
2017	562,728.71	506,456	222,148	0.3948	340,581	0.50	340,581	4.5
TOTAL	15,678,639.98	14,572,515	6,391,978		9,286,662		9,286,662	

COMPOSITE ANNUAL ACCRUAL RATE 59.23%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.41

COMPOSITE AVERAGE AGE (YEARS) 7.54

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 0.50

Enbridge Gas Distribution

Account #: 482.05 - General Plant - Structures and Improvements - Markham

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2046

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2011	147,807.89	52,250	31,358	0.2122	116,450	19.20	6,064	10.5
2012	31,727,969.48	10,465,736	6,281,077	0.1980	25,446,892	19.30	1,318,475	9.5
2013	480,360.14	146,466	87,902	0.1830	392,458	19.38	20,254	8.5
2014	28,044.58	7,810	4,687	0.1671	23,357	19.43	1,202	7.5
2015	350,547.36	87,779	52,681	0.1503	297,866	19.46	15,308	6.5
2016	53,237.11	11,736	7,043	0.1323	46,194	19.45	2,375	5.5
2017	2,424,985.17	456,656	274,065	0.1130	2,150,921	19.40	110,893	4.5
2018	557,163.34	85,617	51,384	0.0922	505,780	19.28	26,238	3.5
2019	901,703.23	104,609	62,782	0.0696	838,922	19.05	44,039	2.5
TOTAL	36,671,818.30	11,418,658	6,852,980		29,818,839		1,544,848	

COMPOSITE ANNUAL ACCRUAL RATE 4.21%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.19

COMPOSITE AVERAGE AGE (YEARS) 8.86

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 19.30

Enbridge Gas Inc.

Account #: 482.51 - General Plant - Structures and Improvements - Keil Head Office
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2049

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1967	13,561,856.85	12,047,160	5,330,016	0.3930	8,231,841	6.85	1,201,322	54.5
1975	446.57	373	165	0.3692	282	9.22	31	46.5
1979	6,216,146.70	4,979,943	2,203,272	0.3544	4,012,874	10.55	380,365	42.5
1981	13,941.98	10,911	4,827	0.3463	9,115	11.25	810	40.5
1985	66,514.62	49,346	21,832	0.3282	44,683	12.70	3,518	36.5
1997	379,854.39	224,020	99,113	0.2609	280,742	17.04	16,473	24.5
2000	1,277,664.70	695,333	307,635	0.2408	970,029	18.01	53,873	21.5
2001	21,783.20	11,507	5,091	0.2337	16,692	18.31	912	20.5
2002	319,247.25	163,411	72,298	0.2265	246,950	18.60	13,280	19.5
2003	177,371.10	87,800	38,845	0.2190	138,526	18.87	7,340	18.5
2004	345,763.11	165,155	73,069	0.2113	272,694	19.14	14,249	17.5
2005	2,288,214.33	1,052,042	465,454	0.2034	1,822,760	19.39	94,015	16.5
2006	615,728.02	271,720	120,217	0.1952	495,511	19.62	25,251	15.5
2007	3,758,480.63	1,586,827	702,059	0.1868	3,056,422	19.84	154,023	14.5
2008	738,700.30	297,260	131,516	0.1780	607,184	20.05	30,287	13.5
2009	50,411.58	19,250	8,517	0.1689	41,895	20.23	2,070	12.5
2010	230,329.13	83,028	36,734	0.1595	193,595	20.40	9,489	11.5
2011	537,306.10	181,697	80,388	0.1496	456,918	20.55	22,234	10.5
2012	3,754,845.50	1,182,099	522,995	0.1393	3,231,851	20.68	156,309	9.5
2013	120,106.76	34,870	15,427	0.1284	104,679	20.78	5,038	8.5
2014	756,715.04	200,178	88,565	0.1170	668,150	20.85	32,043	7.5
2015	45,824.26	10,874	4,811	0.1050	41,013	20.89	1,963	6.5
2016	790,984.23	164,841	72,930	0.0922	718,054	20.89	34,370	5.5
2017	561,981.30	99,815	44,161	0.0786	517,820	20.84	24,852	4.5
2018	11,296,540.09	1,633,672	722,784	0.0640	10,573,756	20.70	510,764	3.5
2019	4,408,233.57	480,391	212,539	0.0482	4,195,695	20.44	205,260	2.5

Enbridge Gas Inc.

Account #: 482.51 - General Plant - Structures and Improvements - Keil Head Office

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2049

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2020	344,597.48	24,114	10,669	0.0310	333,929	19.94	16,750	1.5
2021	16,879,086.37	438,510	194,010	0.0115	16,685,077	18.75	890,063	0.5
TOTAL	69,558,675.16	26,196,143	11,589,939		57,968,736		3,906,954	

COMPOSITE ANNUAL ACCRUAL RATE	5.62%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.17
COMPOSITE AVERAGE AGE (YEARS)	18.53
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	16.39

Enbridge Gas Inc.

Account #: 482.52 - General Plant - Structures and Improvements - Bloomfield Training Center

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: R1.5
ASL: 40
Net Salvage: 0%
Truncation Year: 2028

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1993	2,769,967.65	2,289,629	359,174	0.1297	2,410,794	5.98	403,212	28.5
2006	77,583.70	55,349	8,683	0.1119	68,901	6.23	11,065	15.5
2010	3,572.99	2,313	363	0.1016	3,210	6.26	512	11.5
2015	15,770,377.95	8,015,945	1,257,460	0.0797	14,512,918	6.29	2,308,055	6.5
2016	7,325.00	3,418	536	0.0732	6,789	6.29	1,080	5.5
2017	571,743.83	238,537	37,419	0.0654	534,325	6.29	85,003	4.5
2020	37,121.15	7,200	1,129	0.0304	35,992	6.23	5,774	1.5
TOTAL	19,237,692.27	10,612,391	1,664,764		17,572,928		2,814,701	

COMPOSITE ANNUAL ACCRUAL RATE	14.63%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.09
COMPOSITE AVERAGE AGE (YEARS)	9.64
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	6.24

Enbridge Gas Distribution

Account #: 483.00 - General Plant - Office Furniture and Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	1,547,876.38	1,496,281	1,547,876	1.0000	0	0.50	0	14.5
2008	1,553,124.29	1,397,812	1,553,124	1.0000	0	1.50	0	13.5
2009	900,993.44	750,828	900,993	1.0000	0	2.50	0	12.5
2010	2,986,237.93	2,289,449	2,986,238	1.0000	0	3.50	0	11.5
2011	5,308,576.65	3,716,004	5,148,386	0.9698	160,190	4.50	35,598	10.5
2012	3,368,001.99	2,133,068	2,133,068	0.6333	1,234,934	5.50	224,533	9.5
2013	2,710,535.67	1,535,970	1,535,970	0.5667	1,174,565	6.50	180,702	8.5
2014	1,505,699.50	752,850	752,850	0.5000	752,850	7.50	100,380	7.5
2015	5,464,200.44	2,367,820	2,367,820	0.4333	3,096,380	8.50	364,280	6.5
2016	2,741,359.73	1,005,165	1,005,165	0.3667	1,736,195	9.50	182,757	5.5
2017	897,281.50	269,184	269,184	0.3000	628,097	10.50	59,819	4.5
2018	245,022.65	57,172	57,172	0.2333	187,851	11.50	16,335	3.5
2019	259,637.87	43,273	43,273	0.1667	216,365	12.50	17,309	2.5
2020	190,363.95	19,036	19,036	0.1000	171,328	13.50	12,691	1.5
2021	97,149.73	3,238	3,238	0.0333	93,911	14.50	6,477	0.5
TOTAL	29,776,061.72	17,837,150	20,323,396		9,452,666		1,200,881	

COMPOSITE ANNUAL ACCRUAL RATE 4.03%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.68

COMPOSITE AVERAGE AGE (YEARS) 8.99

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 6.01

Enbridge Gas Distribution

Account #: 484.00 - General Plant - Transportation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L2.5
ASL: 12
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1995	5,886.93	5,586	5,887	1.0000	0	1.43	0	26.5
1996	83,994.02	79,244	83,994	1.0000	0	1.53	0	25.5
1997	52,226.12	48,954	52,226	1.0000	0	1.64	0	24.5
1998	50,541.63	47,030	50,542	1.0000	0	1.75	0	23.5
1999	86,150.36	79,496	86,150	1.0000	0	1.88	0	22.5
2000	18,051.76	16,498	18,052	1.0000	0	2.03	0	21.5
2001	42,775.16	38,665	42,775	1.0000	0	2.18	0	20.5
2002	229,028.25	204,437	229,028	1.0000	0	2.35	0	19.5
2003	16,122.29	14,187	16,122	1.0000	0	2.52	0	18.5
2004	66,451.06	57,544	66,451	1.0000	0	2.71	0	17.5
2005	836,851.01	711,832	836,851	1.0000	0	2.90	0	16.5
2006	1,377,310.68	1,148,806	1,377,311	1.0000	0	3.08	0	15.5
2007	2,855,091.60	2,332,028	2,855,092	1.0000	0	3.25	0	14.5
2008	6,726,949.02	5,375,289	6,726,949	1.0000	0	3.39	0	13.5
2009	3,296,003.61	2,573,632	3,296,004	1.0000	0	3.51	0	12.5
2010	4,821,371.64	3,669,887	4,821,372	1.0000	0	3.61	0	11.5
2011	10,705,900.73	7,902,079	10,705,901	1.0000	0	3.73	0	10.5
2012	4,796,858.36	3,401,124	4,796,858	1.0000	0	3.90	0	9.5
2013	9,324,424.44	6,260,667	9,324,424	1.0000	0	4.16	0	8.5
2014	13,104,260.47	8,171,056	11,486,923	0.8766	1,617,338	4.53	357,181	7.5
2015	13,077,169.99	7,387,071	9,971,241	0.7625	3,105,929	5.01	620,341	6.5
2016	4,897,079.13	2,429,250	3,279,058	0.6696	1,618,021	5.59	289,587	5.5
2017	11,632,470.15	4,866,831	6,569,362	0.5647	5,063,109	6.26	809,361	4.5
2018	9,886,113.84	3,299,250	4,453,404	0.4505	5,432,709	6.99	777,472	3.5
2019	17,270,979.10	4,205,624	5,676,850	0.3287	11,594,129	7.77	1,492,820	2.5
2020	10,417,592.94	1,546,344	2,087,292	0.2004	8,330,301	8.61	968,035	1.5

Enbridge Gas Distribution

Account #: 484.00 - General Plant - Transportation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L2.5
ASL: 12
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2021	9,044,423.40	451,696	609,710	0.0674	8,434,713	9.51	886,780	0.5
TOTAL	134,722,077.69	66,324,107	89,525,829		45,196,249		6,201,576	

COMPOSITE ANNUAL ACCRUAL RATE	4.60%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.66
COMPOSITE AVERAGE AGE (YEARS)	6.50
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	5.72

Enbridge Gas Distribution

Account #: 485.00 - General Plant - Heavy Work Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L1.5
ASL: 17
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1991	24,477.11	21,807	14,543	0.5941	9,934	3.73	2,660	30.5
1996	57,293.11	48,475	32,327	0.5642	24,966	4.64	5,382	25.5
1997	153,581.23	128,305	85,565	0.5571	68,017	4.83	14,092	24.5
1998	566,336.21	466,731	311,257	0.5496	255,080	5.02	50,862	23.5
1999	5,501.12	4,468	2,980	0.5416	2,522	5.20	485	22.5
2000	44,256.52	35,387	23,599	0.5332	20,657	5.39	3,833	21.5
2001	225,036.23	176,949	118,005	0.5244	107,032	5.57	19,212	20.5
2002	170,705.94	131,842	87,924	0.5151	82,782	5.75	14,402	19.5
2003	530,446.58	401,865	267,998	0.5052	262,448	5.92	44,338	18.5
2004	1,297,998.39	963,141	642,305	0.4948	655,693	6.08	107,769	17.5
2005	785,151.61	569,602	379,860	0.4838	405,292	6.24	64,910	16.5
2006	1,365,513.31	966,436	644,503	0.4720	721,011	6.40	112,649	15.5
2007	1,132,626.49	779,908	520,110	0.4592	612,517	6.56	93,404	14.5
2008	2,495,276.47	1,665,951	1,111,000	0.4452	1,384,276	6.72	205,981	13.5
2009	1,772,253.56	1,142,229	761,737	0.4298	1,010,517	6.89	146,565	12.5
2010	6,975,444.40	4,315,716	2,878,092	0.4126	4,097,353	7.09	578,124	11.5
2011	2,345,474.49	1,383,151	922,404	0.3933	1,423,070	7.31	194,798	10.5
2012	1,136,773.17	633,184	422,261	0.3715	714,512	7.56	94,567	9.5
2013	1,744,541.95	906,998	604,865	0.3467	1,139,677	7.85	145,198	8.5
2014	2,014,513.49	962,576	641,929	0.3187	1,372,585	8.20	167,465	7.5
2015	2,059,334.05	886,564	591,238	0.2871	1,468,096	8.60	170,741	6.5
2016	165,150.70	62,448	41,646	0.2522	123,505	9.05	13,654	5.5
2017	1,082,169.54	347,287	231,601	0.2140	850,569	9.52	89,324	4.5
2018	3,490,404.68	902,969	602,178	0.1725	2,888,227	10.03	287,983	3.5
2019	1,977,122.87	378,257	252,254	0.1276	1,724,869	10.57	163,226	2.5
2020	6,382,757.51	758,259	505,673	0.0792	5,877,085	11.13	528,208	1.5

Enbridge Gas Distribution

Account #: 485.00 - General Plant - Heavy Work Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: L1.5
ASL: 17
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2021	4,128,780.23	170,065	113,414	0.0275	4,015,366	11.64	344,998	0.5
TOTAL	44,128,920.96	19,210,570	12,811,266		31,317,655		3,664,828	

COMPOSITE ANNUAL ACCRUAL RATE	8.30%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	8.17
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	8.55

Enbridge Gas Distribution

Account #: 486.00 - General Plant - Tools and Work Equipment
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2000	0.00	0	0	0.0000	0	0.00	0	21.5
2001	0.00	0	0	0.0000	0	0.00	0	20.5
2007	3,961,806.89	3,829,747	2,526,117	0.6376	1,435,690	0.50	1,435,690	14.5
2008	5,913,146.36	5,321,832	3,510,303	0.5936	2,402,844	1.50	1,601,896	13.5
2009	2,354,607.71	1,962,173	1,294,258	0.5497	1,060,350	2.50	424,140	12.5
2010	5,781,919.10	4,432,805	2,923,897	0.5057	2,858,022	3.50	816,578	11.5
2011	3,577,126.15	2,503,988	1,651,641	0.4617	1,925,485	4.50	427,886	10.5
2012	3,663,115.28	2,319,973	1,530,264	0.4177	2,132,851	5.50	387,791	9.5
2013	4,095,836.08	2,320,974	1,530,924	0.3738	2,564,912	6.50	394,602	8.5
2014	16,180,032.47	8,090,016	5,336,209	0.3298	10,843,824	7.50	1,445,843	7.5
2015	6,286,115.38	2,723,983	1,796,751	0.2858	4,489,364	8.50	528,161	6.5
2016	4,352,180.39	1,595,799	1,052,596	0.2419	3,299,584	9.50	347,325	5.5
2017	5,806,688.57	1,742,007	1,149,035	0.1979	4,657,654	10.50	443,586	4.5
2018	3,840,750.35	896,175	591,121	0.1539	3,249,629	11.50	282,576	3.5
2019	8,667,286.86	1,444,548	952,830	0.1099	7,714,457	12.50	617,157	2.5
2020	3,675,931.58	367,593	242,466	0.0660	3,433,466	13.50	254,331	1.5
2021	1,810,311.19	60,344	39,803	0.0220	1,770,508	14.50	122,104	0.5
TOTAL	79,966,854.36	39,611,957	26,128,214		53,838,641		9,529,664	

COMPOSITE ANNUAL ACCRUAL RATE	11.92%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	7.43
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	7.57

Enbridge Gas Distribution

Account #: 487.70 - General Plant - Rental - Refuel Appliances
CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2010	6,325.54	4,850	1,359	0.2149	4,966	3.50	1,419	11.5
2011	15,903.43	11,132	3,120	0.1962	12,783	4.50	2,841	10.5
2012	55,313.16	35,032	9,818	0.1775	45,495	5.50	8,272	9.5
2014	14,464.61	7,232	2,027	0.1401	12,438	7.50	1,658	7.5
2015	328,514.61	142,356	39,899	0.1215	288,616	8.50	33,955	6.5
2016	234,947.75	86,148	24,145	0.1028	210,803	9.50	22,190	5.5
2018	169,405.73	39,528	11,079	0.0654	158,327	11.50	13,768	3.5
2020	18,405.86	1,841	516	0.0280	17,890	13.50	1,325	1.5
2021	21,473.92	716	201	0.0093	21,273	14.50	1,467	0.5
TOTAL	864,754.61	328,834	92,164		772,591		86,894	

COMPOSITE ANNUAL ACCRUAL RATE 10.05%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.11

COMPOSITE AVERAGE AGE (YEARS) 5.70

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 9.30

Enbridge Gas Distribution

Account #: 487.80 - General Plant - Rental - NGV Stations

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	13,855.60	3,118	13,856	1.0000	0	15.50	0	4.5
2019	2,212,175.03	276,522	2,022,160	0.9141	190,015	17.50	10,858	2.5
2020	4,448,475.41	333,636	333,636	0.0750	4,114,840	18.50	222,424	1.5
2021	1,099,668.82	27,492	27,492	0.0250	1,072,177	19.50	54,983	0.5
TOTAL	7,774,174.86	640,767	2,397,143		5,377,032		288,265	

COMPOSITE ANNUAL ACCRUAL RATE	3.71%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	1.65
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	18.35

Enbridge Gas Distribution

Account #: 488.00 - General Plant - Communication Structures and Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2007	307,126.40	307,126	184,237	0.5999	122,890	0.00	122,890	14.5
2008	128,223.13	128,223	76,918	0.5999	51,306	0.00	51,306	13.5
2010	1,561,084.54	1,561,085	936,452	0.5999	624,632	0.00	624,632	11.5
2011	809,669.52	809,670	485,699	0.5999	323,971	0.00	323,971	10.5
2012	1,185,159.94	1,125,902	675,398	0.5699	509,762	0.50	509,762	9.5
2013	522,285.32	443,943	266,309	0.5099	255,976	1.50	170,651	8.5
2014	2,082,386.97	1,561,790	936,876	0.4499	1,145,511	2.50	458,205	7.5
2015	1,489,428.62	968,129	580,754	0.3899	908,675	3.50	259,621	6.5
2016	1,250,210.87	687,616	412,482	0.3299	837,729	4.50	186,162	5.5
2017	1,361,551.69	612,698	367,541	0.2699	994,011	5.50	180,729	4.5
2018	26,564.77	9,298	5,577	0.2100	20,987	6.50	3,229	3.5
2019	317,207.03	79,302	47,571	0.1500	269,636	7.50	35,951	2.5
2020	153,462.71	23,019	13,809	0.0900	139,654	8.50	16,430	1.5
2021	30,247.69	1,512	907	0.0300	29,340	9.50	3,088	0.5
TOTAL	11,224,609.20	8,319,312	4,990,530		6,234,079		2,946,627	

COMPOSITE ANNUAL ACCRUAL RATE	26.25%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.44
COMPOSITE AVERAGE AGE (YEARS)	7.82
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	2.59

Enbridge Gas Distribution

Account #: 490.00 - General Plant - Computer Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 4
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2018	6,964,752.60	6,094,159	6,964,753	1.0000	0	0.50	0	3.5
2019	11,281,679.70	7,051,050	9,742,129	0.8635	1,539,551	1.50	1,026,367	2.5
2020	10,240,619.70	3,840,232	3,840,232	0.3750	6,400,387	2.50	2,560,155	1.5
2021	1,819,626.69	227,453	227,453	0.1250	1,592,173	3.50	454,907	0.5
TOTAL	30,306,678.69	17,212,894	20,774,567		9,532,112		4,041,429	

COMPOSITE ANNUAL ACCRUAL RATE	13.34%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	2.27
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	1.73

Enbridge Gas Inc.

Account #: 490.30 - General Plant - Computer Equipment - WAMS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2016	4,680,899.13	2,574,495	2,418,465	0.5167	2,262,435	4.50	502,763	5.5
TOTAL	4,680,899.13	2,574,495	2,418,465		2,262,435		502,763	

COMPOSITE ANNUAL ACCRUAL RATE	10.74%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	5.50
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	4.50

Enbridge Gas Distribution

Account #: 491.01 - Software - Acquired Intangibles

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 4
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2017	5,933,217.48	5,933,217	5,933,217	1.0000	0	0.00	0	4.5
2018	24,321,547.69	21,281,354	24,321,548	1.0000	0	0.50	0	3.5
2019	64,148,946.33	40,093,091	64,148,946	1.0000	0	1.50	0	2.5
2020	5,286,014.31	1,982,255	5,286,014	1.0000	0	2.50	0	1.5
2021	55,475,059.58	6,934,382	7,860,612	0.1417	47,614,448	3.50	13,604,128	0.5
TOTAL	155,164,785.39	76,224,301	107,550,337		47,614,448		13,604,128	

COMPOSITE ANNUAL ACCRUAL RATE	8.77%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	1.98
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	2.04

Enbridge Gas Distribution

Account #: 491.02 - Software - Developed Intangibles

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 4
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2018	9,486,577.80	8,300,756	9,486,578	1.0000	0	0.50	0	3.5
2019	5,619,946.21	3,512,466	5,619,946	1.0000	0	1.50	0	2.5
2020	9,566,744.92	3,587,529	8,649,956	0.9042	916,789	2.50	366,716	1.5
2021	14,103,018.70	1,762,877	1,762,877	0.1250	12,340,141	3.50	3,525,755	0.5
TOTAL	38,776,287.63	17,163,629	25,519,357		13,256,930		3,892,470	

COMPOSITE ANNUAL ACCRUAL RATE	10.04%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.66
COMPOSITE AVERAGE AGE (YEARS)	1.77
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	2.23

Enbridge Gas Distribution

Account #: 491.03 - Software - CIS Acquired

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2015	13,559,337.94	8,813,570	13,559,338	1.0000	0	3.50	0	6.5
2020	13,812,372.94	2,071,856	3,678,108	0.2663	10,134,265	8.50	1,192,266	1.5
2021	60,254,502.69	3,012,725	3,012,725	0.0500	57,241,778	9.50	6,025,450	0.5
TOTAL	87,626,213.57	13,898,151	20,250,171		67,376,042		7,217,717	

COMPOSITE ANNUAL ACCRUAL RATE 8.24%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.23

COMPOSITE AVERAGE AGE (YEARS) 1.59

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 8.41

Enbridge Gas Distribution

Account #: 491.04 - Software - WAMS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ELG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year: 2050

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2016	85,221,905.36	46,872,048	44,031,318	0.5167	41,190,587	4.50	9,153,464	5.5
TOTAL	85,221,905.36	46,872,048	44,031,318		41,190,587		9,153,464	

COMPOSITE ANNUAL ACCRUAL RATE	10.74%
COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	5.50
DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS)	4.50

APPENDIX 2 – GENERATION ARRANGEMENT

Year	O/C	% Surviving	Realized Life	Remaining Life	Average Life	Average Life Weighting	Remaining Life Weighted	% of Age
2020	$166,467,753.49	1	0.5	54.45011	54.95011	$3,029,434.40	$164,953,036.29	1
2019	$169,518,061.00	0.9987362	1.499368121	53.35297	54.78491293	$3,094,247.16	$165,087,275.66	3
2018	$135,161,276.10	0.9956823	2.496733859	52.26221	54.53329379	$2,478,509.31	$129,532,373.80	5
2017	$130,644,750.98	0.9929497	3.493199857	51.72013	54.84868853	$2,381,912.03	$123,192,799.79	6
2016	$134,743,490.85	0.9926143	4.487125166	50.644165	54.75724582	$2,460,742.66	$124,622,257.41	8
2015	$132,583,819.17	0.990181	5.47858391	49.580685	54.57243457	$2,429,501.64	$120,456,355.40	10
2014	$114,471,994.72	0.9860834	6.459341555	48.53123	54.31518302	$2,107,550.57	$102,282,021.27	12
2013	$129,288,463.71	0.9866361	7.458055044	47.497175	54.32048434	$2,380,105.13	$113,048,270.11	14
2012	$132,609,246.89	0.9867351	8.458305129	46.98628	54.82131535	$2,418,935.88	$113,656,798.73	15
2011	$109,673,888.23	0.9865406	9.457879567	45.97703	54.8160867	$2,000,761.00	$91,989,048.34	17
2010	$94,882,973.86	0.9569939	10.27262805	44.98527	53.3232588	$1,779,391.88	$80,046,424.27	19
2009	$94,034,887.10	0.9512124	11.23529956	44.01144	53.09952565	$1,770,917.65	$77,940,635.83	21
2008	$85,357,220.05	0.9577144	12.2489302	43.05576	53.48405084	$1,595,937.83	$68,714,316.20	23
2007	$86,824,916.79	0.9564844	13.22914078	42.118505	53.51483372	$1,622,445.79	$68,334,991.22	25
2006	$86,197,475.07	0.9534973	14.21656045	41.656835	53.93624127	$1,598,136.49	$66,573,307.88	26
2005	$75,534,461.97	0.9622345	15.24241162	40.7473	54.45087144	$1,387,203.91	$56,524,814.04	28
2004	$31,699,476.96	0.9608712	16.2155016	39.856135	54.51211279	$581,512.54	$23,176,842.15	30
2003	$88,707,161.04	0.9533743	17.19945351	38.98323	54.36506504	$1,631,694.20	$63,608,710.09	32
2002	$70,067,655.19	0.9557835	18.18852872	38.128365	54.63098972	$1,282,562.43	$48,902,008.65	34
2001	$86,124,769.07	0.951695	19.16461542	37.707615	55.05076382	$1,564,460.93	$58,992,090.36	35
2000	$101,347,895.65	0.9516235	20.15298932	36.87926	55.24816086	$1,834,412.12	$67,651,761.36	37
1999	$83,310,424.95	0.9414527	21.09473979	36.068285	55.0513232	$1,513,322.84	$54,582,959.60	39
1998	$72,787,533.07	0.9418222	22.05541695	35.27425	55.27748872	$1,316,766.28	$46,447,942.88	41
1997	$62,899,623.44	0.9338346	22.96115701	34.49688	55.17553733	$1,139,991.14	$39,326,137.40	43
1996	$83,643,103.29	0.9241689	23.90726381	33.73568	55.08473158	$1,518,444.42	$51,225,755.05	45
1995	$79,727,399.46	0.9214801	24.82712078	33.36102	55.56863662	$1,434,755.36	$47,864,902.39	46
1994	$73,141,662.99	0.9097574	25.74662554	32.623415	55.42601741	$1,319,626.89	$43,050,735.68	48
1993	$61,155,996.30	0.8875992	26.56188882	31.90099	54.87718312	$1,114,415.73	$35,550,965.18	50
1992	$54,560,231.27	0.867434	27.37442607	31.19336	54.43260837	$1,002,344.60	$31,266,496.07	52
1991	$42,434,642.83	0.8466413	28.00864143	30.50014	53.83132056	$788,289.09	$24,042,927.68	54
1990	$37,810,664.67	0.8359965	28.75653683	30.158755	53.96914925	$700,597.75	$21,129,155.97	55
1989	$33,159,265.08	0.8006342	29.20587448	29.486325	52.81363339	$627,854.27	$18,513,114.97	57
1988	$34,872,348.64	0.7990594	29.99207586	28.827205	53.02672371	$657,637.25	$18,957,843.76	59
1987	$31,479,834.90	0.776213	30.48483368	28.18101	52.35930128	$601,227.18	$16,943,189.09	61
1986	$30,021,047.17	0.7695827	31.29334893	27.54741	52.49335826	$571,901.82	$15,754,413.94	63
1985	$23,970,218.26	0.6742394	30.71723906	26.925965	48.87178443	$490,471.52	$13,206,418.91	65
1984	$29,638,308.32	0.726636	32.53298048	26.61967	51.87579157	$571,332.17	$15,208,673.70	66

Year	O/C	% Surviving	Realized Life	Remaining Life	Average Life	Average Life Weighting	Remaining Life Weighted	% of Age
1983	$22,003,784.80	0.6673129	32.49824085	26.015715	49.85886253	$441,321.44	$11,481,292.70	68
1982	$18,981,458.29	0.5637107	31.63047751	25.42298	45.96168268	$412,984.41	$10,499,294.33	70
1981	$23,163,506.83	0.5901532	33.02438479	24.841135	47.68445898	$485,766.38	$12,066,988.12	72
1980	$21,619,311.82	0.5790782	33.71587251	24.269795	47.76998213	$452,571.07	$10,983,807.04	74
1979	$20,516,302.76	0.6265885	35.45747842	23.98792	50.48803339	$406,359.71	$9,747,724.29	75
1978	$12,905,012.40	0.5481899	34.89058362	23.431705	47.73560804	$270,343.52	$6,334,609.66	77
1977	$10,660,880.56	0.5192311	35.17644716	22.88517	47.05913869	$226,542.19	$5,184,456.64	79
1976	$9,677,488.30	0.4735827	35.17761163	22.34804	45.76125719	$211,477.76	$4,726,113.51	81
1975	$9,331,651.06	0.4571167	35.72575882	21.81993	45.70001333	$204,193.62	$4,455,490.45	83
1974	$7,587,810.98	0.3482489	34.44761101	21.30062	41.86552754	$181,242.45	$3,860,576.66	85
1973	$9,732,918.85	0.4070965	36.8767794	21.044155	45.44378072	$214,174.94	$4,507,130.56	86
1972	$5,958,964.14	0.3118413	35.91910011	20.53744	42.32352194	$140,795.56	$2,891,580.45	88
1971	$6,605,226.12	0.4243598	38.60992541	20.03881	47.11359028	$140,197.89	$2,809,398.95	90
1970	$3,855,499.05	0.3243282	37.07619512	19.54799	43.41615985	$88,803.32	$1,735,926.37	92
1969	$4,692,232.99	0.3553312	38.47022228	19.06476	45.24452689	$103,708.30	$1,977,173.86	94
1968	$4,514,909.45	0.4114711	40.74145163	18.825895	48.48776257	$93,114.41	$1,752,962.12	95
1967	$3,098,730.29	0.3609923	40.39274971	18.3535	47.01822179	$65,904.88	$1,209,585.22	97
1966	$2,643,997.39	0.3474752	40.69771466	17.888145	46.91340183	$56,359.11	$1,008,159.86	99
1965	$1,738,821.63	0.2447012	39.08757377	17.4295	43.35259377	$40,108.83	$699,076.78	101
1964	$1,078,278.19	0.1272243	36.48128157	16.977345	38.64121265	$27,904.87	$473,750.68	103
1963	$2,501,879.45	0.2726265	41.1161837	16.53157	45.62312722	$54,837.96	$906,557.66	105
1962	$3,291,752.09	0.3881532	44.8066728	16.310965	51.13782536	$64,370.20	$1,049,940.09	106
1961	$2,243,819.05	0.3304099	44.10358691	15.874265	49.34860094	$45,468.75	$721,782.94	108
1960	$1,160,862.23	0.18786	41.59788735	15.443395	44.49908361	$26,087.33	$402,876.92	110
1959	$653,668.62	0.1237838	41.1126195	15.01819	42.97162748	$15,211.63	$228,451.19	112
1958	$1,547,722.72	0.2179915	43.30757894	14.598485	46.48992467	$33,291.57	$486,006.53	114
1957	$1,485,635.23	0.321896	47.29618982	14.390585	51.92846212	$28,609.27	$411,704.09	115
1956	$784,103.40	0.3732633	49.8362607	13.9788	55.05403343	$14,242.43	$199,092.13	117
1955	$388,827.42	0.6346525	59.46757651	13.57202	68.08109346	$5,711.24	$77,513.05	119
1954	$1,372,088.36	0.6306644	61.18470964	13.170135	69.49064435	$19,744.94	$260,043.48	121
	$3,306,351,087.00					$61,370,803.83	$2,525,506,837.43	
						1.86%		

CHAPTER IX

THE GENERATION ARRANGEMENT

Definition and Purpose

Under the straight-line method of depreciation accounting, the book investment, less its net salvage, is recovered over the average service life of the property. The average service life is estimated by blending past experience with forecasts of the future. The generation arrangement[1] is a process that accomplishes this blending.

In the generation arrangement, each generation represents a vintage of surviving property. The generation arrangement produces both the average service life and average remaining life. The average service life of the category is calculated from the vintage average lives.

There is a significant difference between the average life relating to a vintage group and the average service life relating to a category. The average life of a vintage group is an arithmetical average of the lives of its surviving and retired component units, whereas the average service life of the category is the reciprocal, or accrual weighted average, of the average lives of the component groups of a category. The average service life of a category changes according to the changing composition of its surviving groups.

The principal advantage of the generation arrangement is that it permits maximum utilization of actual experience. All available statistical data are used to calculate each vintage's average life and then are used to calculate the composite category average service life. Under the whole life technique, the average service life is used to calculate the whole life depreciation rate. In the remaining life technique, the vintage average life serves as a basis for weighting the vintage remaining lives which are used to calculate the category average remaining life. This composite average remaining life is then used to calculate the remaining life depreciation rate. Methods of weighting are discussed later in this chapter.

Therefore, the generation arrangement is used with both the whole life and remaining life techniques. The process can also be used with the ELG procedure (see Chapter XII). The generation arrangement allows some vintages in a category to be studied under the ELG procedures, and some vintages in the category may also be studied under other procedures using either the whole life or remaining life techniques.

Most property, with the exception of major equipment installations, consists of groups of many relatively small but easily identifiable items. These items are similar to one another, but the life of each item is not dependent upon the lives of the others. Furthermore, all items placed in service, in any one year seldom, if ever, retire simultaneously. Instead, the retirements are spread over many years according to a life table pattern. These are the mass property categories. The generation arrangement also provides a sound basis for calculating the average service life of major structure categories that are studied on a life span basis. This is

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[1] The generation arrangement is typically used only by the telephone industry. Therefore, the discussion in this chapter will be in reference to telephone plant equipment.

especially true where obsolescence has taken hold and no new major installations are being made but substantial investment is necessary to keep the plant in service.

Components

Table 9-1 illustrates the generation arrangement for a mass property category of plant. The plant is being studied, using historical data through December 31, 1995.

Table 9-2 shows for the 1990 vintage the Amount (investment) Surviving (Column B), the Proportion Surviving (Column F), and the Realized Life (Column G). Information such as that shown in Table 9-2 is required for each vintage included in the generation arrangement. Table 9-3 shows the calculation of the Average Remaining Life for each vintage (Column D).

The components of this generation arrangement are described and explained below. A definition is given for each column; the derivation of Columns B through E of Table 9-1 is shown in Tables 9-2 and 9-3. Descriptions of the columns in Table 9-1 are as follows:

Column A: Age of the surviving plant in service is as of January 1, 1996. It is assumed that plant is added evenly throughout the year; therefore, on the average at mid-year. For example, the age of the 1995 vintage is one-half year. The age of the 1990 vintage is 5.5 years.

Column B: Amount Surviving is the amount of investment surviving from the original vintage placement reduced by adjustments and retirements.

Column C: Proportion Surviving is the proportion of an original vintage placement that has survived retirement.

Column D: Realized Life is the life realized by the original addition in a vintage from the date placed to the study date.

Column E: Average Remaining Life is the average number of years remaining before retirement of each vintage. (See Table 9-3).

Column F: Average Life is a combination of the past and the future lives. The vintage average life is the sum of the Realized Life (Column D) and the Unrealized Life, which is the product of the Proportion Surviving (Column C) and the Remaining Life (Column E).

Column G: Average Life Weight is the Amount Surviving (Column B) divided by the Average Life (Column F).

Column H: Remaining Life Weight is the product of the Average Life Weight (Column G) and the Remaining Life (Column E).

TABLE 9-1

GENERATION ARRANGEMENT

Vintage	Age as of 1/1/96 A	Experience to 12-31-95 Amount Surviving B	Proportion Surviving C	Realized Life D	Remaining Life (Years) E	Average Life (Years) F=D+C*E	Average Life Weight G=B/F	Remaining Life Weight H=E*G
1995	0.5	398,962	.9974	0.50	11.55	12.02	33,192	383,362
1994	1.5	357,089	.9831	1.48	10.68	11.98	29,897	318,340
1993	2.5	350,607	.9609	2.45	9.86	11.92	29,413	290,016
1992	3.5	291,323	.9488	3.42	9.08	12.04	24,196	219,702
1991	4.5	288,689	.9217	4.34	8.34	12.03	23,997	200,139
1990	5.5	127,166[1]	.5877[2]	4.52[3]	7.64[4]	9.01	14,113	107,830
1989	6.5	237,510	.8995	6.30	6.98	12.58	18,880	131,782
1988	7.5	166,770	.8626	7.14	6.37	12.63	13,204	84,109
1987	8.5	114,267	.8312	7.97	5.79	12.78	8,941	51,768
1986	9.5	79,389	.7895	8.83	5.26	12.98	6,116	32,170
1985	10.5	64,080	.7227	9.45	4.76	12.89	4,971	23,662
1984	11.5	62,361	.7044	10.17	4.30	13.20	4,724	20,313
1983	12.5	44,466	.6279	10.45	3.87	12.88	3,452	13,359
1982	13.5	35,322	.5919	11.08	3.48	13.14	2,688	9,354
1981	14.5	34,756	.5893	12.29	3.12	14.13	2,460	7,675
1980	15.5	35,205	.5176	12.44	2.79	13.88	2,536	7,075
1979	16.5	47,210	.5112	13.51	2.50	14.79	3,192	7,980
1978	17.5	34,564	.4098	14.82	2.23	15.73	2,197	4,900
1977	18.5	29,676	.4470	15.88	1.98	16.77	1,770	3,505
1976	19.5	35,282	.3824	16.50	1.77	17.18	2,054	3,636
1975	20.5	27,505	.4241	17.57	1.57	18.24	1,508	2,368
1974	21.5	16,158	.3731	17.95	1.40	18.47	875	1,225
1973	22.5	14,437	.3556	18.46	1.24	18.90	764	947
1972	23.5	10,682	.2623	19.04	1.11	19.33	553	614
1971	24.5	13,194	.2281	20.77	.99	21.00	628	622
1970	25.5	11,710	.1783	20.98	.88	21.14	554	488
1969	26.5	6,660	.1274	21.62	.50	21.68	307	154
		2,935,040			8.1 [5]	12.4 [6]	237,902	1,927,095

[1] *See Table 9-2, Column B for Activity Year 1996.*

[2] *See Table 9-2, Column F for Activity Year 1996.*

[3] *See Table 9-2, Column G for Activity Year 1996.*

[4] *See Table 9-3, Column D for Age 5.5.*

[5] *Composite Average Remaining Life = Total of Column H/Total of Column G.*

[6] *Composite Average Service Life = Total of Column B/Total of Column G.*

The development of Proportion Surviving (Column C) and Realized Life (Column D) is provided on Table 9-2 for the plant placed in 1990. One might expect the Proportion Surviving (Column C) of Table 9-1 to resemble the life table used to derive remaining lives, (Column B) of Table 9-3. This would assume that future retirements will follow the same pattern as past retirements, which is unlikely considering how erratic past retirements were. Note in Table 9-2, only 65.4% of the plant in service at the beginning of the third year survived to the end of that year. Of the plant in service at the beginning of the fourth year 96.3% survived to the end of that year. It is improbable that this performance will be repeated. The average remaining lives developed in Table 9-3 are derived from the projection life table (see Chapter VIII).

TABLE 9-2

VINTAGE YEAR 1990
DEVELOPMENT OF PROPORTION SURVIVING AND REALIZED LIFE

Activity Year A	Balance Beginning of Year B	Original Addition and Adjustments C	Retirements D	Survival Ratio E=(B-D)/B	Proportion Surviving Beginning of Year F(A)=E(A-1)*F(A-1)	Realized Life Beginning of Year $G(A)=\sum_{F(1)}^{F(A-1)} F(A) + 0.5*F(A)$
1990		230,225	414	.9982	1.000	
1991	229,811	(87)	666	.9971	.9982	0.50
1992	229,058	(2,063)	4,535	.9802	.9953	1.50
1993	222,460	(5,278)	77,038	.6537	.9756	2.48
1994	140,144	(942)	5,161	.9632	.6377	3.29
1995	134,041	(1,088)	5,787	.9568	.6142	3.91
1996	127,166				.5877	4.52

Column A: The calendar year in which additions, retirements, and adjustments occur from the 1990 vintage.

Column B: Amount surviving from original 1990 placement after adjustments and retirements. Note the value at activity year 1996. This figure (127,166) appears in the Generation Arrangement (Column B) at age 5.5.

Column C: The 1990 entry shows the original addition. Subsequent entries show transfer adjustments.

Column D: Amount retired each activity year.

Column E: Ratio of plant less retirements to plant balance.

Column F: The previous amount in Column E multiplied by the previous amount in Column F. The value at activity year 1996 (.5877) appears in the Generation Arrangement (Column C) at age 5.5.

Column G: The calculation for the 1990 vintage at 1996 involves summing the proportion surviving amounts from 1991 through 1995 plus one-half of the 1996 amount. The value at 1996, (4.52, rounded) appears in the Generation Arrangement (Column D) at age 5.5.

TABLE 9-3

PROJECTION LIFE TABLE/REMAINING LIFE DEVELOPMENT

Age A	Proportion in Service B[2]	Summation of Life Table $C = \sum_{B+1}^{END} B$	Average Remaining Life D=[C/B]+0.5
0.5	.99574	11.0041	11.55
1.5	.98391	10.0202	10.68
2.5	.96723	9.0530	9.86
3.5	.94520	8.1078	9.08
4.5	.91735	7.1904	8.34
5.5	.88328	6.3072	7.64
6.5	.84273	5.4644	6.98
7.5	.79557	4.6689	6.37
8.5	.74193	3.9269	5.79
9.5	.68220	3.2447	5.26
10.5	.61713	2.6276	4.76
11.5	.54785	2.0797	4.30
12.5	.47588	1.6039	3.87
13.5	.40310	1.2008	3.48
14.5	.33168	.8691	3.12
15.5	.26392	.6052	2.79
16.5	.20202	.4031	2.50
17.5	.14787	.2553	2.23
18.5	.10278	.1525	1.98
19.5	.06730	.0852	1.77
20.5	.04113	.0441	1.57
21.5	.02321	.0209	1.40
22.5	.01195	.0089	1.24
23.5	.00553	.0034	1.11
24.5	.00226	.0011	0.99
25.5	.00080	.0003	0.88
26.5	.00024	.0000	0.50
27.5	.00006	.0000	0.50
28.5	.00000	.0000	0.50
	11.99986		

Column A: These are the same ages as shown in the Generation Arrangement.

Column B: Life table values based on a 12-year Gompertz-Makeham curve. Alternatively, generalized curves, such as the Iowa curves, could be used.

Column C: This value at each age is the sum of the life table values beyond that age. For example, the value at age 6.5 (5.4644) is found by adding the life table values from age 7.5 (.79557) through age 28.5 (.00001).

Column D: The Remaining Life is the number of years remaining before retirement of each vintage. It is calculated by dividing the amount in Column C by the life table value in Column B and adding 0.5 years. For example, the average remaining life at age 8.5 equals (3.9269/.74193) + 0.5. The value at age 5.5 (7.64) appears in the Generation Arrangement (Column E) at age 5.5.

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[2] Based on following Gompertz-Makeham factors: c = 1.1550991; G = -.086446248; S = .0092192171; Projection Life = 12.00 years.

Enbridge Gas Inc.

Account #: 473.00 - Distribution Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2020

ELG - Remaining Life
Survivor Curve: S1
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1954	1,372,088.36	1,159,863	1,372,088	1.0000	0	12.17	0	66.5
1955	388,827.42	326,624	388,827	1.0000	0	12.47	0	65.5
1956	784,103.40	654,420	784,103	1.0000	0	12.78	0	64.5
1957	1,485,635.23	1,231,704	1,485,635	1.0000	0	13.09	0	63.5
1958	1,547,722.72	1,274,427	1,547,723	1.0000	0	13.40	0	62.5
1959	653,668.62	534,467	653,669	1.0000	0	13.72	0	61.5
1960	1,160,862.23	942,312	1,160,862	1.0000	0	14.03	0	60.5
1961	2,243,819.05	1,807,840	2,243,819	1.0000	0	14.35	0	59.5
1962	3,291,752.09	2,631,840	3,291,752	1.0000	0	14.67	0	58.5
1963	2,501,879.45	1,984,524	2,501,879	1.0000	0	14.99	0	57.5
1964	1,078,278.19	848,344	1,078,278	1.0000	0	15.31	0	56.5
1965	1,738,821.63	1,356,550	1,738,822	1.0000	0	15.64	0	55.5
1966	2,643,997.39	2,044,868	2,643,997	1.0000	0	15.97	0	54.5
1967	3,098,730.29	2,375,141	3,098,730	1.0000	0	16.30	0	53.5
1968	4,514,909.45	3,428,693	4,514,909	1.0000	0	16.63	0	52.5
1969	4,692,232.99	3,529,389	4,692,233	1.0000	0	16.97	0	51.5
1970	3,855,499.05	2,871,450	3,855,499	1.0000	0	17.31	0	50.5
1971	6,605,226.12	4,869,256	6,605,226	1.0000	0	17.65	0	49.5
1972	5,958,964.14	4,346,548	5,958,964	1.0000	0	17.99	0	48.5
1973	9,732,918.85	7,021,890	9,732,919	1.0000	0	18.34	0	47.5
1974	7,587,810.98	5,412,460	7,587,811	1.0000	0	18.69	0	46.5
1975	9,331,651.06	6,578,477	9,331,651	1.0000	0	19.04	0	45.5
1976	9,677,488.30	6,739,541	9,677,488	1.0000	0	19.40	0	44.5
1977	10,660,880.56	7,330,976	10,660,881	1.0000	0	19.76	0	43.5
1978	12,905,012.40	8,758,252	12,905,012	1.0000	0	20.12	0	42.5
1979	20,516,302.76	13,734,967	20,516,303	1.0000	0	20.49	0	41.5

Enbridge Gas Inc.

Account #: 473.00 - Distribution Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2020

ELG - Remaining Life
Survivor Curve: S1
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
1980	21,619,311.82	14,269,431	21,619,312	1.0000	0	20.86	0	40.5
1981	23,163,506.83	15,064,638	23,163,507	1.0000	0	21.24	0	39.5
1982	18,981,458.29	12,156,608	18,981,458	1.0000	0	21.61	0	38.5
1983	22,003,784.80	13,868,394	22,003,785	1.0000	0	22.00	0	37.5
1984	29,638,308.32	18,371,043	29,638,308	1.0000	0	22.39	0	36.5
1985	23,970,218.26	14,601,290	23,970,218	1.0000	0	22.78	0	35.5
1986	30,021,047.17	17,957,717	30,021,047	1.0000	0	23.18	0	34.5
1987	31,479,834.90	18,476,045	28,781,647	0.9143	2,698,188	23.58	114,437	33.5
1988	34,872,348.64	20,064,417	20,064,417	0.5754	14,807,931	23.99	617,367	32.5
1989	33,159,265.08	18,685,720	18,685,720	0.5635	14,473,545	24.40	593,197	31.5
1990	37,810,664.67	20,847,069	20,847,069	0.5514	16,963,596	24.82	683,510	30.5
1991	42,434,642.83	22,867,123	22,867,123	0.5389	19,567,519	25.24	775,157	29.5
1992	54,560,231.27	28,702,994	28,702,994	0.5261	25,857,237	25.67	1,007,123	28.5
1993	61,155,996.30	31,369,769	31,369,769	0.5129	29,786,228	26.11	1,140,719	27.5
1994	73,141,662.99	36,531,331	36,531,331	0.4995	36,610,332	26.56	1,378,541	26.5
1995	79,727,399.46	38,717,467	38,717,467	0.4856	41,009,933	27.01	1,518,332	25.5
1996	83,643,103.29	39,431,661	39,431,661	0.4714	44,211,442	27.47	1,609,456	24.5
1997	62,899,623.44	28,736,619	28,736,619	0.4569	34,163,004	27.94	1,222,835	23.5
1998	72,787,533.07	32,166,725	32,166,725	0.4419	40,620,808	28.41	1,429,632	22.5
1999	83,310,424.95	35,539,947	35,539,947	0.4266	47,770,478	28.90	1,653,021	21.5
2000	101,347,895.65	41,640,616	41,640,616	0.4109	59,707,280	29.39	2,031,250	20.5
2001	86,124,769.07	33,996,981	33,996,981	0.3947	52,127,788	29.90	1,743,435	19.5
2002	70,067,655.19	26,500,189	26,500,189	0.3782	43,567,466	30.41	1,432,443	18.5
2003	88,707,161.04	32,046,745	32,046,745	0.3613	56,660,416	30.94	1,831,243	17.5
2004	31,699,476.96	10,901,549	10,901,549	0.3439	20,797,928	31.48	660,700	16.5
2005	75,534,461.97	24,632,113	24,632,113	0.3261	50,902,349	32.03	1,589,169	15.5

Enbridge Gas Inc.

Account #: 473.00 - Distribution Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2020

ELG - Remaining Life
Survivor Curve: S1
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ELG Remaining Life	Annual Accrual	Average Age
2006	86,197,475.07	26,538,626	26,538,626	0.3079	59,658,849	32.60	1,830,250	14.5
2007	86,824,916.79	25,112,660	25,112,660	0.2892	61,712,257	33.18	1,860,197	13.5
2008	85,357,220.05	23,059,998	23,059,998	0.2702	62,297,222	33.77	1,844,800	12.5
2009	94,034,887.10	23,570,709	23,570,709	0.2507	70,464,178	34.38	2,049,627	11.5
2010	94,882,973.86	21,892,425	21,892,425	0.2307	72,990,549	35.01	2,084,993	10.5
2011	109,673,888.23	23,073,332	23,073,332	0.2104	86,600,557	35.66	2,428,772	9.5
2012	132,609,246.89	25,146,432	25,146,432	0.1896	107,462,815	36.32	2,958,404	8.5
2013	129,288,463.71	21,783,016	21,783,016	0.1685	107,505,448	37.01	2,904,402	7.5
2014	114,471,994.72	16,823,340	16,823,340	0.1470	97,648,654	37.73	2,588,206	6.5
2015	132,583,819.17	16,585,117	16,585,117	0.1251	115,998,702	38.47	3,015,476	5.5
2016	134,743,490.85	13,862,542	13,862,542	0.1029	120,880,949	39.24	3,080,565	4.5
2017	130,644,750.98	10,501,220	10,501,220	0.0804	120,143,531	40.04	3,000,349	3.5
2018	135,161,276.10	7,789,140	7,789,140	0.0576	127,372,136	40.88	3,115,656	2.5
2019	169,518,061.00	5,878,038	5,878,038	0.0347	163,640,023	41.76	3,918,692	1.5
2020	166,467,753.49	1,927,553	1,927,553	0.0116	164,540,200	42.68	3,855,106	0.5
TOTAL	3,306,351,087.00	1,005,483,174	1,115,131,552		2,191,219,535		63,567,058	

COMPOSITE ANNUAL ACCRUAL RATE 1.92%

COMPOSITE ACTUAL ACCUMULATED DEPRECIATION FACTOR 0.34

COMPOSITE AVERAGE AGE (YEARS) 15.90

DIRECTED WEIGHTED ELG COMPOSITE REMAINING LIFE (YEARS) 32.75

APPENDIX 3 – LARRY KENNEDY'S CV

LARRY E. KENNEDY, CDP

Senior Vice President

Mr. Kennedy has been in the pipeline, electric, gas utility and municipal infrastructure business for 40 years. As Senior Vice President, Concentric Advisors, ULC, Mr. Kennedy has provided professional consulting services to gas and electric utilities including generation facilities (including nuclear facilities), and high voltage transmission lines, large diameter transmission pipelines, railway systems and municipally owned utility systems. Previously, Mr. Kennedy was with Gannett Fleming Canada ULC, for over 17 years, where he was responsible for completing depreciation studies and provided advice related to large capital program spending and controls for many regulated North American utilities. Mr. Kennedy was also employed by Interprovincial Pipelines Limited (now Enbridge Pipelines) for 15 years in several plant accounting and regulatory positions and with Nova Gas Transmission Pipelines (now TC Energy) for three years as a Depreciation Specialist.

Mr. Kennedy has provided expert witness testimony related to depreciation, stranded costs, capital accounting issues, utility valuation, and property tax issues before several North American regulatory bodies. Mr. Kennedy has completed numerous seminars and all courses offered by Depreciation Programs, Inc. Mr. Kennedy is a member of the teaching faculty of the Society of Depreciation Professionals ("SDP") and has presented depreciation, stranded cost, and capital accounting related topics to the SDP, Canadian Electric Association, Canadian Gas Association, Canadian Property Taxpayers Association, Alberta Utilities Commission, British Columbia Utilities Commission and the Canadian Energy Pipeline Association. Mr. Kennedy is a past Society of Depreciation Professionals President.

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Representative Project Experience

- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and in 2015 for submission to the FERC (Docket No. RP15-1022-000) to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.

- Viking Gas Transmission Company - The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the

Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons, including discussion related to the long demand of natural gas.

- Midwestern Gas Transmission Company: The assignment included development of a detailed depreciation study and Testimony to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons. The Direct Testimony included significant discussion related to the topics of Decarbonization and changing political climate towards removal of fossil fuel demand forecasts.
- Enbridge Lakehead System: A Technical Update to a 2016 full depreciation study was prepared and filed with the FERC in 2021 in support of updating depreciation rate and resultant depreciation expense. The technical update also included an analysis and recommendation of a 20-year Economic Planning Horizon (Economic Life).
- Consolidated Edison Company of New York, Inc.: Mr. Kennedy co-authored a study and report which presented the results of research focusing on prior periods of transformative change and more recent discussions of policy tools that could address the impacts of climate change on the Company's electric, steam, and natural gas businesses.
- Montana-Dakota Utilities Co.: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study and associated expert testimony were submitted to the Montana Public Service Commission in 2018 and to the North Dakota Public Service Commission in 2022. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of the retirement of generation facilities due to environmental legislation and estimation of net salvage requirements.
- Commonwealth Edison Company: Mr. Kennedy sponsored extensive Rebuttal Testimony related to the average service life, net salvage estimations, and appropriate depreciation practices in a 2020 rate proceeding.
- Great Plains Natural Gas Co.: Annual updates of depreciation rates and net salvage requirements were calculated and submitted to the Minnesota Department of Commerce annually since 2017.
- National Grid USA Service Company Limited: A depreciation study was completed in 2020 for the National Grid High Voltage Direct Current (HVDC) electric interstate transmission line. The study included consideration of the average service life of the system components, the level of components of the system and the compliance of the recommended componentization to the FERC Uniform System of Accounts. The resultant study was used by the company in filings with the Federal Energy and Regulatory Commission (FERC)

- Society of Depreciation Professionals (SDP): Mr. Kennedy has presented at the annual conferences on the topic of the erosion of the regulatory compact throughout North America, the Future of Energy transition and its impacts on recovery of investment. Additionally, Mr. Kennedy is a member of the SDP teaching faculty and has lead a number of workshops on various aspects of decarbonization and has co-instructed on the topic of the future of energy.

Other Representative Project Experience

- Alberta Departments of Energy and Forestry and Agriculture: Detailed toll comparison and valuation models were developed to provide a comparison of the toll fairness of each of the Provinces Rural Electrification Associations ("REA") to the comparable Investor Owned Utilities ("IOU") for the 32 REA's currently operating in Alberta. In addition to providing a toll comparison of the REA and IOU, a fair market valuation for each of the REA's was also prepared. The final report of the toll compatibility and specific valuations were submitted to the Alberta Department of Energy and the Alberta Department of Forestry and Agriculture. Mr. Kennedy was the Responsible Officer on this project.
- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.
- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board ("Board"). Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.
- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004, additional depreciation studies were filed in 2005, 2010 and 2012, 2016 and 2018. The 2010, 2012, 2016 and 2018 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards. These studies also specifically analyzed the pace of technical change in the Alberta Electric system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Electric: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities Inc. (NWT) and the distribution assets of Northland Utilities (Yellowknife) Inc. The ATCO Electric studies were submitted to the AUC for review, while the NWT and Northland Utilities (Yellowknife) Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to the Yukon Public Utilities Board. These studies also specifically analyzed the pace of technical and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Gas: Studies were prepared in 2010 and 2018 which were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. These studies also specifically analyzed the pace of technical change in the Alberta Gas system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.

- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006, 2011, and 2015. The 2011 and 2015 studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2016. Mr. Kennedy has also consulted on issues regarding International Financial Reporting Standards ("IFRS") compliance and required componentization.

- Enbridge Gas Distribution Inc.: Full and comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.

- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.

- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Group of Companies: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the British Columbia Utilities Commission ("BCUC") in 2005, 2010, 2011 and 2018 encompassing both the FortisBC electric and natural gas companies. FortisAlberta Inc. studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates. The most recent studies also specifically analyzed the pace of technical change in the Electric systems, and specifically considered the impacts of retirements, system modernization and technical enchantments to the assets.

- International Financial Reporting Standards ("IFRS"): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association and to the BCUC on this topic.

- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada ("NEB").

- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.

- New Brunswick Power: Mr. Kennedy completed a comprehensive depreciation review of the electric generation (including the nuclear facilities), transmission, distribution and general plant assets. The review, which was prepared for submission to the New Brunswick Public Utilities Board, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report.

- Newfoundland and Labrador Hydro (NALCOR): Mr. Kennedy developed comprehensive depreciation studies that included the development of depreciation policy and rates for NALCOR. The studies provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 and 2017 studies were the subject of Regulatory Review in 2012 and 2019.

- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives of the regulated assets of the company's electric generation hydro and nuclear plants were completed in 2011 and 2013 and were submitted to the Ontario Energy Board for review.

- TransCanada Pipelines Limited - Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit-based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012, 2015, and 2018.

- TransCanada Pipelines Limited - Mainline Facilities: The study prepared for submission to the NEB included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta - Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002 and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional full and comprehensive study was completed in 2011, and 2017. The 2011 study was fully supported through an appearance before the NEB in 2012.

Designations and Professional Affiliations

- Society of Depreciation Professionals -Certified Depreciation Professional
- Society of Depreciation Professionals (former President)

EVIDENCE ENTERED INTO PROCEEDINGS IN THE UNITED STATES

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	Alliance Pipeline LP	Alliance Pipeline LP	Federal Energy and Regulatory Commission	Docket No. RP15-1022
2019	Viking Gas Transmission Company	Viking Gas Transmission Company	Federal Energy Regulatory Commission	RP19-1340
2020	National Grid USA Service Company Limited	National Grid USA Service Company Limited	Federal Energy Regulatory Commission	Settled through Negotiation
2018	Great Plains Natural Gas Co.	Great Plains Natural Gas Co.	Minnesota Department of Commerce	Annual Depreciation Filing
2018	Montana-Dakota Utilities	Montana-Dakota Utilities	Montana Public Service Commission	Docket D2019.9
2019	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Cascade Natural Gas Corporation	Cascade Natural Gas Corporation	Oregon Public Utility Commission	UM - 2073
2020	Missouri-American Water Company	Missouri-American Water Company	Missouri Public Service Commission	WR-2020-0344
2020	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Intermountain Gas Company	Intermountain Gas Company	Idaho Public Utilities Commission	Case No. INT-21-01
2021	Midwestern Gas Transmission Company	Midwestern Gas Transmission Company	Federal Energy Regulatory Commission	RP21-525-000
2021	Enbridge Lakehead System	Enbridge Lakehead System	Federal Energy Regulatory Commission	DO21-15-000
2021	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066
2022	Montana-Dakota Utilities	Montana-Dakota Utilities	North Dakota Utilities Commission	pending Montana-Dakota Utilities
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0130
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0155

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2022	Northern Natural Gas Company	Northern Natural Gas Company	Federal Energy Regulatory Commission	pending

EVIDENCE ENTERED INTO PROCEEDINGS IN CANADA

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
1999	ENMAX Power Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2001	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2003	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1279345
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric-ISO Issues	Alberta Energy and Utilities Board	N/A
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Energy and Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	City of Red Deer	City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2008	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1553052
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2010	Enbridge Pipelines Limited· Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1606895
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2011	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	IntraGaz Incorporated	IntraGaz Incorporated	La Regie de L'Energie	R-3807-2012
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 3524
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	N/A
2015	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2015	GazMetro	GazMetro	La Regie de L'Energie	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272
2017	NALCOR	NALCOR	Newfoundland Public Utilities Board	Settled
2017	TransCanada Pipelines Limited – Mainline Facilities	TransCanada Pipelines Limited – Mainline Facilities	National Energy Board of Canada	RH-1-2018
2017	TransCanada Pipelines Limited – NGTL Facilities	TransCanada Pipelines Limited – NGTL Facilities	National Energy Board of Canada	RH-001-2019
2018	WestCoast Transmission System	WestCoast Transmission System	National Energy Board of Canada	Settled
2018	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 24195
2018	ATCO Gas	ATCO Gas	Alberta Utilities Commission	Proceeding 24188
2018	SaskEnergy Inc.	SaskEnergy Inc.	Saskatchewan Review Board	N/A
2018	SaskPower	SaskPower	Saskatchewan Review Board	N/A
2018	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	Proceeding 24161
2018	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 23848
2018	FortisBC Energy Inc.	FortisBC Energy Inc.	British Columbia Utilities Commission	N/A
2018	FortisBC Inc.	FortisBC Inc.	British Columbia Utilities Commission	N/A
2019	Capital Power Corporation	Capital Power Corporation	Municipal Government Board of Alberta	N/A
2019	TransAlta Corporation	TransAlta Corporation	Municipal Government Board of Alberta	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2019	Trans Mountain Pipeline ULC	Trans Mountain Pipeline ULC	Canadian Energy Regulator	T260-2019-04-01
2019	NB Power	NB Power	New Brunswick Energy Utility Regulator	Pending
2019	ATCO Electric	ATCO Electric Transmission	Alberta Utilities Commission	Proceeding 24964
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059
2022	IntraGaz LP	IntraGaz LP	La Regie de L'Energie	R-4189-2022
2022	BC Hydro	BC Hydro	British Columbia Utilities Commission	Project 1599243

2024 Test Year Impact of Proposed Depreciation Rates

Line No.	Particulars ($ millions)	Utility	Plant (1) Average Balance	Current Rate	Proposed Rate	Provision - Current Rate (2)	Provision - Proposed Rate	Proposed Provision Over / (Under) Current Provision	
			(a)	(b)	(c)	(d)	(e)	(f) = (e-d)	/u
	Intangible Plant								
1	Franchises and consents (401)	EGD	0.0			0.0	0.0	0.0	
2		Union	1.2			0.0			
3	Intangible plant - Other (402)	EGD	0.0			0.0	0.0	0.0	
4		Union	0.5			0.0			
5	Total		1.7			0.0	0.0	0.0	
	Local Storage Plant								
6	Structures and Improvements (442)	EGD	0.0		1.69%		0.1	(0.1)	
7		Union	8.5	2.85%		0.2			/u
8	Gas Holders - Storage (443)	EGD	0.0		0.96%		0.1	(0.1)	
9		Union	7.3	2.54%		0.2			/u
10	Gas Holders - Equipment (443)	EGD	0.0		1.06%		0.3	(0.6)	
11		Union	24.8	3.54%		0.9			/u
12	Total		40.5	3.21%	1.17%	1.3	0.5	(0.8)	/u

2024 Test Year Impact of Proposed Depreciation Rates (Continued)

Line No.	Particulars ($ millions)	Utility	Plant (1) Average Balance	Current Rate	Proposed Rate	Provision - Current Rate (2)	Provision - Proposed Rate	Proposed Provision Over / (Under) Current Provision	
			(a)	(b)	(c)	(d)	(e)	(f) = (e-d)	/u
	Storage Plant								
13	Land rights (451)	EGD	42.8	1.16%	1.48%	0.5	1.1	(0.1)	
14		Union	33.7	2.10%		0.7			/u
15	Structures and improvements (452)	EGD	32.3	1.84%	3.94%	0.6	4.5	1.9	
16		Union	83.5	2.50%		2.1			/u
17	Wells (453)	EGD	111.3	1.52%	3.85%	1.7	7.3	3.7	
18		Union	82.6	2.48%		2.0			/u
19	Well equipment (454)	EGD	17.3	5.56%	1.32%	0.9	0.2	(0.7)	
20		Union	0.0			0.0			/u
21	Field Lines (455)	EGD	211.1	1.49%	2.54%	3.6	6.4	1.8	
22		Union	47.8	2.48%		1.0			/u
23	Compressor equipment (456)	EGD	234.2	2.60%	2.88%	6.0	20.9	1.6	
24		Union	491.6	2.68%		13.2			/u
25	Measuring and regulating equipment (457)	EGD	11.2	2.99%	2.60%	0.3	2.8	(0.5)	
26		Union	97.7	3.11%		2.9			/u
27	Total		1,497.2	2.37%	2.89%	35.5	43.2	7.7	/u

2024 Test Year Impact of Proposed Depreciation Rates (Continued)

Line No.	Particulars ($ millions)	Utility	Plant (1) Average Balance	Current Rate	Proposed Rate	Provision - Current Rate (2)	Provision - Proposed Rate	Proposed Provision Over / (Under) Current Provision	
			(a)	(b)	(c)	(d)	(e)	(f) = (e-d)	
	Transmission								
28	Land rights (461)	EGD	19.9	*	1.71%	0.2	1.6	0.1	
29		Union	71.9	1.76%		1.3			/u
30	Compressor structures and improvements (462)	EGD	0.0		2.07%	0.0	3.5	(0.0)	
31		Union	167.5	2.03%		3.5			/u
32	Measuring and regulating structures and	EGD	0.0		1.40%	0.0	0.2	(0.1)	
33	improvements (463)	Union	11.5	2.03%		0.2			/u
34	Equipment (464)	EGD	0.0		2.23%	0.0	0.1	0.0	
35		Union	3.0			0.1			/u
36	Mains (465)	EGD	414.9	*	1.77%	10.2	54.9	(11.7)	
37		Union	2,713.7	1.98%		56.4			/u
38	Compressor equipment (466)	EGD	0.0		3.72%	0.0	38.4	5.6	
39		Union	1,031.8	3.23%		32.8			/u
40	Measuring and regulating equipment (467)	EGD	3.5	*	3.06%	0.1	15.8	2.5	
41		Union	522.9	2.60%		13.3			/u
42	Total		4,960.5	2.38%	2.31%	118.0	114.4	(3.7)	/u

2024 Test Year Impact of Proposed Depreciation Rates (Continued)

Line No.	Particulars ($ millions)	Utility	Plant (1) Average Balance	Current Rate	Proposed Rate	Provision - Current Rate (2)	Provision - Proposed Rate	Proposed Provision Over / (Under) Current Provision	
			(a)	(b)	(c)	(d)	(e)	(f) = (e-d)	
	Distribution Plant								
43	Renewable Natural Gas(3)	EGD	31.4	various	various	1.3	1.2	(0.1)	
44		Union	0.0			0.0			/u
45	Land rights (471)	EGD	45.7	1.18%	1.80%	0.5	1.2	0.3	
46		Union	22.2	1.68%		0.4			/u
47	Structures and improvements - Other (472)	EGD	110.1	5.24%	3.17%	6.7	7.0	(3.2)	
48		Union	148.7	2.32%		3.5			/u
49	Structures and improvements - Stoney Creek	EGD	0.0		4.47%	0.0	1.5	0.7	
50	(472.31)	Union	33.5	2.32%		0.8			/u
51	Structures and improvements - Win-Rhodes	EGD	0.0		4.27%	0.0	1.1	0.5	
52	(472.32)	Union	26.2	2.32%		0.6			/u
53	Structures and improvements - London Admin	EGD	0.0		11.95%	0.0	2.7	2.1	
54	(472.33)	Union	22.4	2.32%		0.5			/u
55	Structures and improvements - Kingston Office	EGD	0.0		4.21%	0.0	0.8	0.3	
56	(472.34	Union	18.9	2.32%		0.5			/u
57	Structures and improvements - Mainway (472.35)	EGD	0.0		50.48%	0.0	9.1	8.6	
58		Union	9.0	2.32%		0.4			/u
59	Services - metallic (473.01)	EGD	320.6	2.27%	3.63%	7.2	22.0	6.1	
60		Union	290.8	3.02%		8.7			/u
61	Services - plastic (473.02)	EGD	3,180.6	2.27%	2.73%	71.5	136.3	16.9	
62		Union	1,855.6	2.56%		47.8			/u
63	Regulators (474)	EGD	315.9	(**)	8.86%	10.1	44.7	25.7	
64		Union	192.5	5.00%		8.9			/u

2024 Test Year Impact of Proposed Depreciation Rates (Continued)

Line No.	Particulars ($ millions)	Utility	Plant (1) Average Balance	Current Rate	Proposed Rate	Provision - Current Rate (2)	Provision - Proposed Rate	Proposed Provision Over / (Under) Current Provision	
			(a)	(b)	(c)	(d)	(e)	(f) = (e-d)	
	Distribution Plant								
65	Mains - Envision (475.00)	EGD	222.2	4.03%	5.78%	8.8	12.6	3.8	
66		Union	0.0			0.0			/u
67	Mains - Coated and wrapped (475.21)	EGD	2,163.5	2.44%	3.38%	52.5	134.7	34.3	
68		Union	1,845.3	2.93%		47.8			/u
69	Mains - Plastic (475.30)	EGD	2,738.0	1.85%	2.72%	50.5	103.5	22.5	
70		Union	1,101.1	2.35%		30.4			/u
71	Company NGV compressor stations (476)	EGD	6.5	5.97%	3.70%	0.4	0.5	(0.2)	
72		Union	6.0	4.00%		0.2			/u
73	Measuring & regulating equipment (477)	EGD	802.7	2.05%	2.89%	16.4	32.4	4.4	
74		Union	329.9	3.72%		11.6			/u
75	Customer M&R Equipment (477.01)(4)	EGD	0.0		3.34%	0.0	5.7	0.8	
76		Union	174.4	2.86%		4.9			/u
77	Meters (478)	EGD	583.8	9.22%	10.25%	53.5	118.5	42.4	
78		Union	580.7	3.93%		22.5			/u
79	Total		17,178.0	2.73%	3.70%	469.1	635.3	166.1	/u

2024 Test Year Impact of Proposed Depreciation Rates (Continued)

Line No.	Particulars ($ millions)	Utility	Plant (1) Average Balance	Current Rate	Proposed Rate	Provision - Current Rate (2)	Provision - Proposed Rate	Proposed Provision Over / (Under) Current Provision	
			(a)	(b)	(c)	(d)	(e)	(f) = (e-d)	
	General Plant								
80	Investment in leased assets	EGD	37.7			1.2	1.5	0.3	
81		Union	0.0			0.0			/u
82	Structures and improvements - Other (482.00)	EGD	9.0	2.98%	1.44%	0.3	0.5	(0.5)	
83		Union	29.0	1.92%		0.7			/u
84	Structures and improvements - VPC (482.01)	EGD	119.4	9.93%	6.36%	11.8	7.6	(4.3)	
85		Union	0.0			0.0			/u
86	Structures and improvements - Thorold (482.04)	EGD	0.0	3.61%	59.23%	0.0	0.0	(0.0)	
87		Union	0.0			0.0			/u
88	Structures and improvements - Markham (482.05)	EGD	37.1	2.18%	4.21%	0.8	1.6	0.8	
89		Union	0.0			0.0			/u
90	Structures and improvements - Keil (482.51)	EGD	0.0		5.62%	0.0	4.4	2.1	
91		Union	78.2	1.92%		2.3			/u
92	Structures and improvements - Bloomfield	EGD	0.0		14.63%	0.0	3.2	2.5	
93	(482.52)	Union	21.6	1.92%		0.6			/u
94	Office furniture and equipment (483)	EGD	28.6	10.74%	4.03%	3.2	1.5	(2.3)	
95		Union	9.4	6.67%		0.6			/u
96	Transportation equipment (484)	EGD	82.5	10.56%	4.65%	8.5	7.2	(11.0)	
97		Union	73.6	13.27%		9.7			/u
98	Heavy work equipment (485)	EGD	29.4	3.58%	8.29%	1.0	4.3	1.7	
99		Union	23.0	6.92%		1.6			/u
100	Tools and other equipment (486)	EGD	53.3	4.08%	11.92%	3.0	10.9	5.3	
101		Union	38.6	6.67%		2.6			/u
102	Rental - refuel appl (487.70)	EGD	0.8	0.74%	10.05%	0.0	0.1	0.1	
103		Union	0.0			0.0			/u

2024 Test Year Impact of Proposed Depreciation Rates (Continued)

Line No.	Particulars ($ millions)	Utility	Plant (1) Average Balance	Current Rate	Proposed Rate	Provision - Current Rate (2)	Provision - Proposed Rate	Proposed Provision Over / (Under) Current Provision	
			(a)	(b)	(c)	(d)	(e)	(f) = (e-d)	
	General Plant								
104	Rental - NGV Stations (487.80)	EGD	8.1	8.01%	3.71%	0.6	0.3	(0.3)	
105		Union	0.0			0.0			/u
106	Communication structures and equipment (488)	EGD	2.0	9.71%	26.25%	0.1	2.6	2.0	
107		Union	7.5	6.67%		0.5			/u
108	Computer equipment (490)	EGD	18.9	36.63%	13.34%	15.1	4.2	(16.0)	
109		Union	17.1	25.00%		5.0			/u
110	Computer equipment - post 2023	EGD	8.5		25.00%	0.0	3.3	3.3	
111		Union	3.6			0.0			/u
112	Software acquired intangibles (491.01)	EGD	84.2	26.32%	8.77%	18.9	15.5	(14.5)	
113		Union	66.7	25.00%		11.1			/u
114	Software acquired intangibles - post 2023	EGI	14.3		25.00%	0.0	2.5	2.5	
115						0.0			/u
116	Software developed intangibles (491.02)	EGD	60.2	21.24%	10.04%	28.0	6.5	(21.5)	
117		Union	0.0	25.00%		0.0			/u
118	Software developed intangibles - post 2023	EGI	14.4		25.00%	0.0	2.7	2.7	
119						0.0			/u
120	CIS acquired software (491.03)	EGD	12.2	10.00%	8.24%	1.2	9.1	(2.2)	
121		Union	98.9	10.00%		10.1			/u
122	TIS/IT software	EGD	0.0		10.00%	0.0	0.0	0.0	
123		Union	0.0			0.0			/u
124	WAMS (491.04)	EGD	89.9	10.00%	10.74%	9.0	9.7	0.7	
125		Union	0.0			0.0			/u
126	Total		1,177.6	12.53%	8.41%	147.6	99.1	(48.5)	/u

2024 Test Year Impact of Proposed Depreciation Rates (Continued)

Line No.	Particulars ($ millions)	Utility	Plant (1) Average Balance	Current Rate	Proposed Rate	Provision - Current Rate (2)	Provision - Proposed Rate	Proposed Provision Over / (Under) Current Provision	
			(a)	(b)	(c)	(d)	(e)	(f) = (e-d)	
127 128	Plant held for future use	EGD	1.7	2.27%	3.63% 2.73%	0.0	0.0	(0.0)	
129	Total	EGI	24,857.3	3.10%	3.59%	771.6	892.4	120.7	/u

Notes:

(1) A simple average of the opening and closing plant balances was used.

(2) Provision - Current Rate represents depreciation on 2024 plant balances using previously approved rates and excluding the impacts of all harmonization and depreciation study changes. Depreciation expense has been allocated to approximate the change in plant balances as a result of asset harmonization. /u

(3) Placeholder to be replaced with actual plant accounts once assets are unitized. Represents forecasted RNG projects in total using a blended rate of assets.

(4) Previously account 474.01 for Union.

(*) Depreciation rate for current provision uses equivalent Distribution Plant account.

(**) Depreciation rate for current provision uses 473 Services.

2019 Actual Utility Depreciation Expense - EGD

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Underground Storage Plant			
1	Land rights	42.8	1.16%	0.5
2	Structures and improvements	31.4	1.84%	0.6
3	Wells	59.2	1.52%	0.9
4	Well Equipment	11.5	5.56%	0.6
5	Field Lines	104.4	1.49%	1.6
6	Compressor Equipment	137.1	2.60%	3.6
7	Measurement and Regulating	11.2	2.99%	0.3
8	Total	397.4		8.1
	Distribution Plant			
9	Land rights	63.8	1.18%	0.8
	Structures and improvements			
10	Structures & improvements		2.70%	
11	VPC		9.93%	
12	Kennedy Road		23.53%	
13	Ottawa		4.81%	
14	Thorold		3.61%	
15	Tech Training (Markham)		2.18%	
16	Brockville		4.89%	
17	Arnprior		4.42%	
18	Eastern Ave		6.86%	
19	Kelfield		7.54%	
20	Ottawa Depot		7.08%	
21	Other		2.98%	
22	Colony Court, Brampton		4.24%	
23	Peterborough		4.24%	
24	Oshawa		4.24%	
25	Subtotal: Structures and improvements	144.9		9.1
26	Services & Meter installations	3,023.1	2.27%	68.9
	Mains			
27	Mains - envision		4.03%	
28	Mains - coated & wrapped steel		2.44%	
29	Mains - plastic		1.85%	
30	Subtotal: Mains	4,611.4		102.1
31	Company NGV Compressor Stations	4.1	5.97%	0.3
32	Measuring & regulating equipment	619.0	2.05%	12.8
33	Meters	463.5	9.22%	41.0
34	Total	8,929.7		234.9

2019 Actual Utility Depreciation Expense - EGD (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General Plant			
35	Leasehold improvements	0.1	60	0.0
	Office furniture and equipment			
36	Office furniture		10.74%	
37	Office equipment		0.15%	
38	Subtotal: Office furniture and equipment	20.7		2.2
39	Transporation equipment	57.3	10.56%	5.4
40	NGV Conversion Kits	2.3	9.00%	0.2
41	Heavy work equipment	17.6	3.58%	0.6
42	Tools and work equipment	50.8	4.08%	2.1
43	NGV rental refueling appliances	1.7	0.74%	0.0
44	NGV refueling stations	7.3	8.01%	0.6
	NGV Cylinders			
45	CO Fleet NGV Cylinders		2.10%	
46	NGV Cylinders		18.93%	
47	Subtotal: NGV Cylinders	0.6		0.0
48	Communications equipment	3.9	9.71%	0.4
49	Computer hardware	28.2	36.63%	3.9
50	CIS acquired software	127.1	10.00%	9.5
	Software			
51	Software acquired		26.32%	
52	Sofware developed		21.24%	
53	Subtotal: Software	225.1		36.9
54	WAMS	92.1	10.00%	9.2
55	Total	634.9		71.1
56	Plant held for future use	1.7	2.27%	0.0
57	Total	9,963.7	3.15%	314.2

Note:
(1) Average of the opening and closing plant balances.

2020 Actual Utility Depreciation Expense - EGD

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Underground Storage Plant			
1	Land rights	42.8	1.16%	0.5
2	Structures and improvements	31.4	1.84%	0.6
3	Wells	65.0	1.52%	1.0
4	Well Equipment	11.8	5.56%	0.6
5	Field Lines	110.8	1.49%	1.6
6	Compressor Equipment	148.3	2.60%	4.3
7	Measurement and Regulating	11.2	2.99%	0.3
8	Total	421.3		8.9
	Distribution Plant			
9	Land rights	63.8	1.18%	0.8
	Structures and improvements			
10	Structures & improvements		2.70%	
11	VPC		9.93%	
12	Kennedy Road		23.53%	
13	Ottawa		4.81%	
14	Thorold		3.61%	
15	Tech Training (Markham)		2.18%	
16	Brockville		4.89%	
17	Arnprior		4.42%	
18	Eastern Ave		6.86%	
19	Kelfield		7.54%	
20	Ottawa Depot		7.08%	
21	Other		2.98%	
22	Colony Court, Brampton		4.24%	
23	Peterborough		4.24%	
24	Oshawa		4.24%	
25	Subtotal: Structures and improvements	148.5		9.0
26	Services & Meter installations	3,198.6	2.27%	73.4
	Mains			
27	Mains - envision		4.03%	
28	Mains - other		23.27%	
29	Mains - coated & wrapped steel		2.44%	
30	Mains - plastic		1.85%	
31	Subtotal: Mains	4,709.7		100.8
32	Company NGV Compressor Stations	5.0	5.97%	0.3
33	Measuring & regulating equipment	657.3	2.05%	13.0
34	Meters	508.6	9.22%	41.3
35	Total	9,291.4		238.5

2020 Actual Utility Depreciation Expense - EGD (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General Plant			
36	Leasehold improvements	0.1	60	0.0
	Office furniture and equipment			
37	Office furniture		10.74%	
38	Office equipment		0.15%	
39	Subtotal: Office furniture and equipment	21.0		2.2
40	Transporation equipment	62.5	10.56%	6.5
41	NGV Conversion Kits	2.7	9.00%	0.3
42	Heavy work equipment	18.8	3.58%	0.7
43	Tools and work equipment	55.1	4.08%	2.4
44	NGV rental refueling appliances	1.8	0.74%	0.0
45	NGV refueling stations	13.8	8.01%	1.4
	NGV Cylinders			
46	CO Fleet NGV Cylinders		2.10%	
47	NGV Cylinders		18.93%	
48	Subtotal: NGV Cylinders	0.8		(0.0)
49	Communications equipment	3.7	9.71%	0.4
50	Computer hardware	31.0	36.63%	5.8
51	CIS acquired software	127.1	10.00%	0.0
	Software			
52	Software acquired		26.32%	
53	Sofware developed		21.24%	
54	Subtotal: Software	244.7		33.2
55	WAMS	92.2	10.00%	9.2
56	Total	675.0		62.0
57	Plant held for future use	1.7	2.27%	0.0
58	Total	10,389.4	2.98%	309.5

Note:
(1) Average of the opening and closing plant balances.

2021 Actual Utility Depreciation Expense - EGD

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Underground Storage Plant			
1	Land and gas storage rights	48.3	1.16%	0.5
2	Structures and improvements	31.8	1.84%	0.6
3	Wells	81.2	1.52%	1.2
4	Well Equipment	13.0	5.56%	0.8
5	Field Lines	121.6	1.49%	1.8
6	Compressor Equipment	177.9	2.60%	4.5
7	Measurement and Regulating	11.2	2.99%	0.3
8	Total	485.0		9.7
	Distribution Plant			
9	Land rights	63.8	1.18%	0.8
	Structures and improvements			
10	Structures & improvements		2.70%	
11	VPC		9.93%	
12	Kennedy Road		23.53%	
13	Ottawa		4.81%	
14	Thorold		3.61%	
15	Tech Training (Markham)		2.18%	
16	Brockville		4.89%	
17	Arnprior		4.42%	
18	Eastern Ave		6.86%	
19	Kelfield		7.54%	
20	Ottawa Depot		7.08%	
21	Other		2.98%	
22	Colony Court, Brampton		4.24%	
23	Peterborough		4.24%	
24	Oshawa		4.24%	
25	Subtotal: Structures and improvements	173.5		11.1
26	Services & Meter installations	3,403.5	2.27%	76.4
	Mains			
27	Mains - envision		4.03%	
28	Mains - other		23.27%	
29	Mains - coated & wrapped steel		2.44%	
30	Mains - plastic		1.85%	
31	Subtotal: Mains	4,843.1		109.4
32	Company NGV Compressor Stations	5.4	5.97%	0.3
33	Measuring & regulating equipment	691.6	2.05%	15.1
34	Meters	523.5	9.22%	41.0
35	Total	9,704.3		254.0

2021 Actual Utility Depreciation Expense - EGD (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General Plant			
36	Leasehold improvements	0.1	60	0.0
	Office furniture and equipment			
37	Office furniture		10.74%	
38	Office equipment		0.15%	
39	Subtotal: Office furniture and equipment	21.1		2.2
40	Transporation equipment	64.4	10.56%	6.2
41	NGV Conversion Kits	2.9	9.00%	0.3
42	Heavy work equipment	21.9	3.58%	0.7
43	Tools and work equipment	60.3	4.08%	2.4
44	NGV rental refueling appliances	1.8	0.74%	0.0
45	NGV refueling stations	14.1	8.01%	(0.2)
	NGV Cylinders			
46	CO Fleet NGV Cylinders		2.10%	
47	NGV Cylinders		18.93%	
48	Subtotal: NGV Cylinders	0.8		0.0
49	Communications equipment	2.7	9.71%	0.3
50	Computer hardware	29.9	36.63%	2.7
51	CIS acquired software	70.6	10.00%	21.8
	Software			
52	Software acquired		26.32%	
53	Sofware developed		21.24%	
54	Subtotal: Software	247.1		12.5
55	WAMS	92.1	10.00%	9.2
56	Total	629.8		58.3
57	Plant held for future use	1.7	2.27%	0.0
58	Total	10,820.8	2.98%	322.1

Note:
(1) Average of the opening and closing plant balances.

2022 Estimate Utility Depreciation Expense - EGD

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Underground Storage Plant			
1	Land and gas storage rights	49.2	1.16%	0.5
2	Structures and improvements	32.2	1.84%	0.6
3	Wells	95.4	1.52%	1.4
4	Well equipment	14.4	5.56%	0.8
5	Field Lines	134.1	1.49%	2.0
6	Compressor equipment	203.8	2.60%	5.3
7	Measuring and regulating equipment	11.2	2.99%	0.3
8	Total	540.3		10.9
	Distribution Plant			
9	Renewable Natural Gas (2)	6.0	Various	0.3
10	Land rights intangibles	64.2	1.18%	0.8
	Structures and improvements			
11	Structures & improvements		2.70%	
12	VPC		9.93%	
13	Kennedy Road		23.53%	
14	Ottawa		4.81%	
15	Thorold		3.61%	
16	Tech Training (Markham)		2.18%	
17	Brockville		4.89%	
18	Arnprior		4.42%	
19	Eastern Ave		6.86%	
20	Kelfield		7.54%	
21	Ottawa Depot		7.08%	
22	Other		2.98%	
23	Colony Court, Brampton		4.24%	
24	Peterborough		4.24%	
25	Oshawa		4.24%	
26	Subtotal: Structures and improvements	215.9		7.2
27	Services, house reg & meter install.	3,573.2	2.27%	80.3
	Mains			
28	Mains - envision		4.03%	
29	Mains - other		23.27%	
30	Mains - coated & wrapped steel		2.44%	
31	Mains - plastic		1.85%	
32	Subtotal: Mains	5,139.0		132.6
33	NGV station compressors	5.2	5.97%	0.3
34	Measuring and regulating equip.	706.5	2.05%	14.5
35	Meters	538.0	9.22%	49.0
36	Total	10,248.0		284.8

2022 Estimate Utility Depreciation Expense - EGD (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General Plant			
37	Investment in leased assets	18.3		1.2
38	Lease improvements	0.1	60	0.0
	Office furniture and equipment			
39	Office furniture		10.74%	
40	Office equipment		0.15%	
41	Subtotal: Office furniture and equipment	21.2		2.3
42	Transportation equipment	69.9	10.56%	7.3
43	NGV conversion kits	3.0	9.00%	0.3
44	Heavy work equipment	25.3	3.58%	0.9
45	Tools and work equipment	64.8	4.08%	2.6
46	Rental equipment	1.8	0.74%	0.0
47	NGV rental compressors	7.8	8.01%	0.7
	NGV Cylinders			
48	CO Fleet NGV Cylinders		2.10%	
49	NGV Cylinders		18.93%	
50	Subtotal: NGV Cylinders	0.6		0.0
51	Communication structures & equip.	1.7	9.71%	0.2
52	Computer equipment	28.8	36.63%	2.9
53	CIS	13.1	10.00%	(13.6)
	Software			
54	Software acquired		26.32%	
55	Sofware developed		21.24%	
56	Subtotal: Software	259.0		59.7
57	WAMS	92.0	10.00%	9.2
58	Total	607.6		73.6
59	Plant held for future use	1.7	2.27%	0.0
60	Total	11,397.6	3.24%	369.3

Notes:
(1) Average of the opening and closing plant balances.
(2) Represents forecasted RNG projects in total using a blended rate of assets.

2023 Bridge Year Utility Depreciation Expense - EGD

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Underground Storage Plant			
1	Land and gas storage rights	49.5	1.16%	0.5
2	Structures and improvements	32.3	1.84%	0.6
3	Wells	100.3	1.52%	1.5
4	Well equipment	15.8	5.56%	0.9
5	Field Lines	142.2	1.49%	2.1
6	Compressor equipment	219.1	2.60%	5.6
7	Measuring and regulating equipment	11.2	2.99%	0.3
8	Total	570.3		11.6
	Distribution Plant			
9	Renewable Natural Gas (2)	17.7	Various	0.7
10	Land rights intangibles	64.9	1.18%	0.8
	Structures and improvements			
11	Structures & improvements		2.70%	
12	VPC		9.93%	
13	Kennedy Road		23.53%	
14	Ottawa		4.81%	
15	Thorold		3.61%	
16	Tech Training (Markham)		2.18%	
17	Brockville		4.89%	
18	Arnprior		4.42%	
19	Eastern Ave		6.86%	
20	Kelfield		7.54%	
21	Ottawa Depot		7.08%	
22	Other		2.98%	
23	Colony Court, Brampton		4.24%	
24	Peterborough		4.24%	
25	Oshawa		4.24%	
26	Subtotal: Structures and improvements	243.5		19.2
27	Services, house reg & meter install.	3,729.5	2.27%	84.2
	Mains			
28	Mains - envision		4.03%	
29	Mains - other		23.27%	
30	Mains - coated & wrapped steel		2.44%	
31	Mains - plastic		1.85%	
32	Subtotal: Mains	5,370.3		118.2
33	NGV station compressors	5.7	5.97%	0.3
34	Measuring and regulating equip.	755.9	2.05%	15.3
35	Meters	560.1	9.22%	51.4
36	Total	10,747.6		290.1

2023 Bridge Year Utility Depreciation Expense - EGD (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General Plant			
37	Investment in leased assets	30.1		1.8
38	Lease improvements	0.1	60	0.0
	Office furniture and equipment			
39	Office furniture		10.74%	
40	Office equipment		0.15%	
41	Subtotal: Office furniture and equipment	24.8		2.9
42	Transportation equipment	74.8	10.56%	7.9
43	NGV conversion kits	3.4	9.00%	0.3
44	Heavy work equipment	27.9	3.58%	1.0
45	Tools and work equipment	70.7	4.08%	2.9
46	Rental equipment	1.8	0.74%	0.0
47	NGV rental compressors	7.5	8.01%	0.6
	NGV Cylinders			
48	CO Fleet NGV Cylinders		2.10%	
49	NGV Cylinders		18.93%	
50	Subtotal: NGV Cylinders	0.6		0.0
51	Communication structures & equip.	1.3	9.71%	0.1
52	Computer equipment	33.7	36.63%	10.3
53	CIS	12.2	10.00%	1.2
	Software			
54	Software acquired		26.32%	
55	Sofware developed		21.24%	
56	Subtotal: Software	293.5		42.1
57	WAMS	92.0	10.00%	9.2
58	Total	674.5		80.4
59	Plant held for future use	1.7	2.27%	0.0
60	Total	11,994.1	3.19%	382.1

Notes:
(1) Average of the opening and closing plant balances.
(2) Represents forecasted RNG projects in total using a blended rate of assets.

2019 Actual Utility Depreciation Expense - UGL

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Intangible Plant			
1	Franchises and consents	1.2		0.1
2	Intangible plant - Other	0.5		0.0
3	Total	1.7		0.1
	Local Storage Plant			
4	Structures and improvements	4.7	2.85%	0.1
5	Gas holders - storage	4.6	2.54%	0.1
6	Gas holders - equipment	20.0	3.54%	0.7
7	Regulatory Overheads	2.4	30 years	0.1
8	Total	31.7		1.1
	Storage			
9	Land rights	32.0	2.10%	0.7
10	Structures and improvements	68.8	2.50%	1.7
11	Wells	47.1	2.48%	1.2
12	Field Lines	46.6	2.48%	1.2
13	Compressor equipment	467.8	2.68%	12.5
14	Measuring & regulating equipment	85.7	3.11%	2.7
15	Regulatory Overheads	16.9	35 years	0.5
16	Total	764.9		20.3
	Transmission			
17	Land rights	64.2	1.76%	1.1
18	Structures and improvements	165.1	2.03%	3.4
19	Mains	1,832.6	1.98%	35.6
20	Compressor equipment	939.9	3.23%	30.3
21	Measuring & regulating equipment	285.9	2.60%	7.2
22	Regulatory Overheads	165.6	40 years	4.1
23	Total	3,453.3		81.7

2019 Actual Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Distribution - Southern Operations			
24	Land rights	8.1	1.65%	0.1
25	Structures and improvements	135.3	2.22%	3.0
26	Services - metallic	125.0	2.81%	3.5
27	Services - plastic	911.8	2.51%	22.7
28	Regulators	87.4	5.00%	4.3
29	Regulator and meter installations	72.3	2.80%	2.0
30	Mains - metallic	539.7	2.83%	14.9
31	Mains - plastic	660.0	2.31%	15.1
32	Measuring & regulating equipment	47.1	3.66%	1.6
33	Meters	344.5	3.82%	13.1
34	Regulatory Overheads	245.3	35 years	6.8
35	Total	3,176.4		87.1
	Distribution - Northern & Eastern Operations			
36	Land rights	10.4	1.71%	0.2
37	Structures and improvements	67.2	2.41%	1.6
38	Services - metallic	107.4	3.22%	3.5
39	Services - plastic	472.0	2.60%	12.2
40	Regulators	36.6	5.00%	1.8
41	Regulator and meter installations	40.6	2.92%	1.2
42	Mains - metallic	605.6	3.02%	17.8
43	Mains - plastic	235.6	2.38%	5.6
44	Measuring & regulating equipment	142.9	3.77%	5.3
45	Meters	86.3	4.03%	3.5
46	Regulatory Overheads	161.0	35 years	4.5
47	Total	1,965.6		56.9

2019 Actual Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General			
48	Structures and improvements	71.3	1.92%	1.5
49	Office furniture and equipment	10.1	6.67%	0.7
	Office equipment - computers			
50	Office equipment - computers		25.00%	
51	Office equipment - computers		10.00%	
52	Subtotal: Office equipment - computers	103.9		24.3
53	Transporation equipment	62.4	13.27%	8.1
54	Heavy work equipment	17.5	6.92%	1.1
55	Tools and other equipment	36.4	6.67%	2.4
56	NGV Fuel Equipment	1.7	4.00%	0.1
57	Communications equipment	14.0	6.67%	1.0
58	Regulatory Overheads	53.2	10 years	5.2
59	Total	370.5		44.3
60	Total	9,764.1	2.99%	291.5

Note:
(1) Average of the opening and closing plant balances.

2020 Actual Utility Depreciation Expense - UGL

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Intangible Plant			
1	Franchises and consents	1.2		0.1
2	Intangible plant - Other	0.5		0.0
3	Total	1.7		0.1
	Local Storage Plant			
4	Structures and improvements	5.0	2.85%	0.1
5	Gas holders - storage	4.6	2.54%	0.1
6	Gas holders - equipment	20.1	3.54%	0.7
7	Regulatory Overheads	2.4	30 years	0.1
8	Total	32.1		1.1
	Storage			
9	Land rights	32.0	2.10%	0.7
10	Structures and improvements	69.0	2.50%	1.7
11	Wells	47.6	2.48%	1.2
12	Field Lines	48.7	2.48%	1.2
13	Compressor equipment	470.1	2.68%	12.6
14	Measuring & regulating equipment	85.8	3.11%	2.7
15	Regulatory Overheads	17.8	35 years	0.5
16	Total	771.1		20.5
	Transmission			
17	Land rights	66.8	1.76%	1.2
18	Structures and improvements	166.1	2.03%	3.4
19	Mains	1,917.5	1.98%	37.4
20	Compressor equipment	941.7	3.23%	30.4
21	Measuring & regulating equipment	310.0	2.60%	7.8
22	Regulatory Overheads	188.4	40 years	4.7
23	Total	3,590.6		84.8

2020 Actual Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Distribution - Southern Operations			
24	Land rights	8.6	1.65%	0.1
25	Structures and improvements	138.1	2.22%	3.0
26	Services - metallic	127.2	2.81%	3.6
27	Services - plastic	941.2	2.51%	23.6
28	Regulators	94.1	5.00%	4.8
29	Regulator and meter installations	75.2	2.80%	2.1
30	Mains - metallic	569.6	2.83%	15.6
31	Mains - plastic	690.3	2.31%	15.8
32	Measuring & regulating equipment	55.3	3.66%	1.9
33	Meters	364.2	3.82%	13.8
34	Regulatory Overheads	289.9	35 years	8.1
35	Total	3,353.6		92.3
	Distribution - Northern & Eastern Operations			
36	Land rights	10.6	1.71%	0.2
37	Structures and improvements	68.0	2.41%	1.6
38	Services - metallic	109.3	3.22%	3.5
39	Services - plastic	483.9	2.60%	12.5
40	Regulators	40.2	5.00%	2.0
41	Regulator and meter installations	41.2	2.92%	1.2
42	Mains - metallic	653.0	3.02%	19.3
43	Mains - plastic	238.5	2.38%	5.7
44	Measuring & regulating equipment	148.6	3.77%	5.5
45	Meters	92.8	4.03%	3.7
46	Regulatory Overheads	170.9	35 years	4.8
47	Total	2,056.9		60.0

2020 Actual Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General			
48	Structures and improvements	73.4	1.92%	1.5
49	Office furniture and equipment	10.1	6.67%	0.7
	Office equipment - computers			
50	Office equipment - computers		25.00%	
51	Office equipment - computers		10.00%	
52	Subtotal: Office equipment - computers	125.0		28.4
53	Transporation equipment	64.2	13.27%	8.5
54	Heavy work equipment	19.3	6.92%	1.5
55	Tools and other equipment	38.2	6.67%	2.5
56	NGV Fuel Equipment	2.6	4.00%	0.1
57	Communications equipment	14.2	6.67%	1.0
58	Regulatory Overheads	60.8	10 years	6.0
59	Total	407.8		50.1
60	Total	10,213.7	3.02%	308.8

Note:
(1) Average of the opening and closing plant balances.

2021 Actual Utility Depreciation Expense - UGL

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Intangible Plant			
1	Franchises and consents	1.2		0.1
2	Intangible plant - Other	0.5		0.2
3	Total	1.7		0.3
	Local Storage Plant			
4	Structures and improvements	5.5	2.85%	0.1
5	Gas holders - storage	5.0	2.54%	0.1
6	Gas holders - equipment	20.2	3.54%	0.7
7	Regulatory Overheads	1.9	30 years	0.1
8	Total	32.7		1.0
	Storage			
9	Land rights	32.0	2.10%	0.7
10	Structures and improvements	69.7	2.50%	1.7
11	Wells	48.6	2.48%	1.2
12	Field Lines	50.8		1.2
13	Compressor equipment	471.6	2.68%	12.6
14	Measuring & regulating equipment	74.6	3.11%	(1.2)
15	Regulatory Overheads	19.9	35 years	0.5
16	Total	767.2		16.7
	Transmission			
17	Land rights	67.9	1.76%	1.2
18	Structures and improvements	166.7	2.03%	3.4
19	Mains	1,983.4	1.98%	38.9
20	Compressor equipment	944.1	3.23%	30.5
21	Measuring & regulating equipment	343.5	2.60%	12.2
22	Regulatory Overheads	215.8	40 years	5.2
23	Total	3,721.4		91.4

2021 Actual Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Distribution - Southern Operations			
24	Land rights	9.0	1.65%	0.1
25	Structures and improvements	142.9	2.22%	3.1
26	Services - metallic	129.4	2.81%	3.6
27	Services - plastic	976.3	2.51%	24.5
28	Regulators	100.9	5.00%	4.8
29	Regulator and meter installations	82.1	2.80%	2.2
30	Mains - metallic	633.0	2.83%	16.8
31	Mains - plastic	728.4	2.31%	16.6
32	Measuring & regulating equipment	66.8	3.66%	2.4
33	Meters	382.4	3.82%	14.5
34	Regulatory Overheads	335.4	35 years	9.4
35	Total	3,586.6		98.1
	Distribution - Northern & Eastern Operations			
36	Land rights	10.8	1.71%	0.2
37	Structures and improvements	70.0	2.41%	1.7
38	Services - metallic	110.6	3.22%	3.6
39	Services - plastic	497.7	2.60%	12.9
40	Regulators	38.3	5.00%	1.8
41	Regulator and meter installations	41.9	2.92%	1.2
42	Mains - metallic	700.2	3.02%	20.7
43	Mains - plastic	242.5	2.38%	5.7
44	Measuring & regulating equipment	153.4	3.77%	5.7
45	Meters	99.5	4.03%	3.9
46	Regulatory Overheads	189.3	35 years	5.2
47	Total	2,154.3		62.7

2021 Actual Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General			
48	Structures and improvements	81.9	1.92%	1.6
49	Office furniture and equipment	9.7	6.67%	0.6
	Office equipment - computers			
50	Office equipment - computers		25.00%	
51	Office equipment - computers		10.00%	
52	Subtotal: Office equipment - computers	121.2		24.9
53	Transporation equipment	65.3	13.27%	8.6
54	Heavy work equipment	20.1	6.92%	1.3
55	Tools and other equipment	37.3	6.67%	2.4
56	NGV Fuel Equipment	3.9	4.00%	0.1
57	Communications equipment	11.9	6.67%	0.7
58	Regulatory Overheads	67.3	10	6.3
59	Total	418.5		46.7
60	Total	10,682.5	2.97%	316.9

Note:
(1) Average of the opening and closing plant balances.

2022 Estimate Utility Depreciation Expense - UGL

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Intangible Plant			
1	Franchises and consents	1.2		0.0
2	Intangible plant - Other	0.5		0.0
3	Total	1.7		0.0
	Local Storage Plant			
4	Structures and improvements	6.0	2.85%	0.2
5	Gas holders - storage	5.7	2.54%	0.1
6	Gas holders - equipment	20.2	3.54%	0.7
7	Regulatory Overheads	3.2	30 years	0.1
8	Total	35.1		1.1
	Storage			
9	Land rights	32.9	2.10%	0.7
10	Structures and improvements	71.5	2.50%	1.8
11	Wells	50.3	2.48%	1.2
12	Field Lines	51.6	2.48%	1.3
13	Compressor equipment	472.2	2.68%	12.7
14	Measuring & regulating equipment	67.6	3.11%	2.0
15	Regulatory Overheads	22.7	35 years	0.6
16	Total	768.7		20.3
	Transmission Plant			
17	Land rights	68.4	1.76%	1.2
18	Structures and improvements	167.4	2.03%	3.4
19	Mains	2,036.9	1.98%	40.1
20	Compressor equipment	948.2	3.23%	30.6
21	Measuring & regulating equipment	392.4	2.60%	9.9
22	Regulatory Overheads	252.8	40 years	6.1
23	Total	3,866.1		91.2

2022 Estimate Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Distribution - Southern Operations			
24	Land rights	9.2	1.65%	0.2
25	Structures and improvements	150.7	2.22%	3.3
26	Services - metallic	131.8	2.81%	3.7
27	Services - plastic	1,013.2	2.51%	25.4
28	Regulators	108.3	5.00%	5.3
29	Regulator and meter installations	89.1	2.80%	2.5
30	Mains - metallic	706.5	2.83%	19.0
31	Mains - plastic	771.1	2.31%	17.7
32	Measuring & regulating equipment	75.5	3.66%	2.5
33	Meters	406.7	3.82%	15.6
34	Regulatory Overheads	375.3	35	4.9
35	Total	3,837.3		100.0
	Distribution - Northern & Eastern Operations			
36	Land rights	11.0	1.71%	0.2
37	Structures and improvements	73.9	2.41%	1.8
38	Services - metallic	112.4	3.22%	3.6
39	Services - plastic	514.0	2.60%	13.4
40	Regulators	39.0	5.00%	2.0
41	Regulator and meter installations	43.1	2.92%	1.3
42	Mains - metallic	741.0	3.02%	22.8
43	Mains - plastic	253.6	2.38%	6.0
44	Measuring & regulating equipment	160.7	3.77%	6.1
45	Meters	106.2	4.03%	4.1
46	Regulatory Overheads	216.9	35	11.6
47	Total	2,271.7		72.9

2022 Estimate Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General			
48	Structures and improvements	95.2	1.92%	1.7
49	Office furniture and equipment	9.4	6.67%	0.6
	Office equipment - computers			
50	Office equipment - computers		25.00%	
51	Office equipment - computers		10.00%	
52	Subtotal: Office equipment - computers	120.4		21.4
53	Transporation equipment	67.7	13.27%	8.9
54	Heavy work equipment	21.3	6.92%	1.5
55	Tools and other equipment	36.7	6.67%	2.4
56	NGV Fuel Equipment	4.8	4.00%	0.2
57	Communications equipment	9.6	6.67%	0.6
58	Regulatory Overheads	76.7	10	7.4
59	Total	441.9		44.7
60	Total	11,222.5	2.94%	330.4

Note:
(1) Average of the opening and closing plant balances.

2023 Bridge Year Utility Depreciation Expense - UGL

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Intangible Plant			
1	Franchises and consents	1.2		0.0
2	Intangible plant - Other	0.5		0.0
3	Total	1.7		0.0
	Local Storage Plant			
4	Structures and improvements	6.5	2.85%	0.2
5	Gas holders - storage	5.9	2.54%	0.1
6	Gas holders - equipment	20.2	3.54%	0.7
7	Regulatory Overheads	5.8	30 years	0.2
8	Total	38.5		1.2
	Storage			
9	Land rights	33.7	2.10%	0.7
10	Structures and improvements	75.5	2.50%	1.9
11	Wells	61.7	2.48%	1.4
12	Field Lines	63.6	2.48%	1.5
13	Compressor equipment	472.8	2.68%	12.7
14	Measuring and regulating equipment	79.9	3.11%	2.4
15	Regulatory Overheads	25.3	35 years	0.7
16	Total	812.5		21.2
	Transmission			
17	Land rights	69.8	1.76%	1.2
18	Structures and improvements	167.9	2.03%	3.4
19	Mains	2,143.8	1.98%	41.8
20	Compressor equipment	952.2	3.23%	30.7
21	Measuring & regulating equipment	440.6	2.60%	11.2
22	Regulatory Overheads	301.1	40 years	7.3
23	Total	4,075.4		95.7

2023 Bridge Year Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision	
		(a)	(b)	(c)	
	Distribution - Southern Operations				
24	Land rights	9.5	1.65%	0.2	
25	Structures and improvements	157.0	2.22%	3.5	
26	Services - metallic	134.8	2.81%	3.8	
27	Services - plastic	1,048.3	2.51%	26.3	/u
28	Regulators	116.9	5.00%	5.7	
29	Regulator and meter installations	94.1	2.80%	2.6	
30	Mains - metallic	750.0	2.83%	20.1	
31	Mains - plastic	814.7	2.31%	18.7	/u
32	Measuring & regulating equipment	82.4	3.66%	2.7	
33	Meters	434.6	3.82%	16.8	/u
34	Regulatory Overheads	419.6	35	4.9	
35	Total	4,061.8		105.4	
	Distribution - Northern & Eastern Operations				
36	Land rights	11.4	1.71%	0.2	
37	Structures and improvements	77.2	2.41%	1.9	
38	Services - metallic	114.9	3.22%	3.7	
39	Services - plastic	531.1	2.60%	13.8	/u
40	Regulators	42.0	5.00%	2.1	
41	Regulator and meter installations	45.4	2.92%	1.3	
42	Mains - metallic	785.2	3.02%	24.3	
43	Mains - plastic	268.1	2.38%	6.4	/u
44	Measuring & regulating equipment	175.5	3.77%	6.7	
45	Meters	113.4	4.03%	4.5	/u
46	Regulatory Overheads	242.6	35	13.6	
47	Total	2,406.9		78.5	

2023 Bridge Year Utility Depreciation Expense - UGL (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	General			
48	Structures and improvements	107.0	1.92%	2.0
49	Office furniture and equipment	9.5	6.67%	0.6
	Office equipment - computers			
50	Office equipment - computers		25.00%	
51	Office equipment - computers		10.00%	
52	Subtotal: Office equipment - computers	119.8		16.7
53	Transporation equipment	70.6	13.27%	9.3
54	Heavy work equipment	22.0	6.92%	1.5
55	Tools and other equipment	38.2	6.67%	2.5
56	NGV Fuel Equipment	5.4	4.00%	0.2
57	Communications equipment	9.0	6.67%	0.6
58	Regulatory Overheads	89.5	10 years	8.7
59	Total	470.9		42.2
60	Total	11,867.7	2.90%	344.2

Note:
(1) Average of the opening and closing plant balances.

2024 Test Year Depreciation Expense - EGI

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
	Intangible Plant			
1	Franchises and consents	1.2		0.0
2	Intangible plant - Other	0.5		0.0
3	Total	1.7		0.0
	Local Storage Plant			
4	Structures and improvements	8.5	1.69%	0.1
5	Gas holders - storage	7.3	0.96%	0.1
6	Gas holders - equipment	24.8	1.06%	0.3
7	Total	40.5		0.5
	Underground Storage Plant			
8	Land rights	76.5	1.48%	1.1
9	Structures and improvements	115.8	3.94%	4.5
10	Wells	193.9	3.85%	7.3
11	Wells Equipment	17.3	1.32%	0.2
12	Field Lines	259.0	2.54%	6.4
13	Compressor equipment	725.8	2.88%	20.9
14	Measuring & regulating equipment	108.9	2.60%	2.8
15	Total	1,497.2		43.2
	Transmission Plant			
16	Land rights	91.8	1.71%	1.6
17	Compressor Structures and improvements	167.5	2.07%	3.5
18	Measuring and Regulating Structures and Improvements	11.5	1.40%	0.2
19	Equipment	3.0	2.23%	0.1
20	Mains	3,128.6	1.77%	54.9
21	Compressor equipment	1,031.8	3.72%	38.4
22	Measuring & regulating equipment	526.4	3.06%	15.8
23	Total	4,960.5		114.4

2024 Test Year Depreciation Expense - EGI (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision	
		(a)	(b)	(c)	
	Distribution Plant				
24	Renewable Natural Gas (2)	31.4	Various	1.2	
25	Land rights	68.0	1.80%	1.2	
26	Structures and improvements - Other	258.8	3.17%	7.0	
27	Structures and improvements - Stoney Creek	33.5	4.47%	1.5	
28	Structures and improvements - Win-Rhodes	26.2	4.27%	1.1	
29	Structures and improvements - London Admin	22.4	11.95%	2.7	
30	Structures and improvements - Kingston Office	18.9	4.21%	0.8	
31	Structures and improvements - Mainway	9.0	50.48%	9.1	
32	Services - metallic	611.4	3.63%	22.0	/u
33	Services - plastic	5,036.2	2.73%	136.3	/u
34	Regulators	508.3	8.86%	44.7	
35	Mains - Envision	222.2	5.78%	12.6	
36	Mains - coated and wraped	4,008.8	3.38%	134.7	
37	Mains - plastic	3,839.1	2.72%	103.5	/u
38	Company NGV Compressor Stations	12.4	3.70%	0.5	
39	Measuring & regulating equipment	1,132.6	2.89%	32.4	
40	Customer M&R Equipment	174.4	3.34%	5.7	
41	Meters	1,164.5	10.25%	118.5	/u
42	Total	17,178.0		635.3	
	General				
43	Investment in leased assets	37.7		1.5	
44	Structures and improvements - Other	37.9	1.44%	0.5	
45	Structures and improvements - VPC	119.4	6.36%	7.6	
46	Structures and improvements - Thorold	0.0	59.23%	0.0	
47	Structures and improvements - Markham	37.1	4.21%	1.6	
48	Structures and improvements - Keil	78.2	5.62%	4.4	
49	Structures and improvements - Bloomfield	21.6	14.63%	3.2	
50	Office furniture and equipment	38.0	4.03%	1.5	
51	Transporation equipment	156.1	4.65%	7.2	
52	Heavy work equipment	52.4	8.29%	4.3	
53	Tools and other equipment	91.9	11.92%	10.9	
54	Rental - Refuel Appl	0.8	10.05%	0.1	
55	Rental - NGV Stations	8.1	3.71%	0.3	
56	Communications structures and equipment	9.6	26.25%	2.6	
57	Computer Equipment	36.0	13.34%	4.2	
58	Computer Equipment - post 2023	12.1	25.00%	3.3	

2024 Test Year Depreciation Expense - EGI (Continued)

Line No.	Particulars ($ millions)	Plant (1) Average Balance	Rate	Provision
		(a)	(b)	(c)
59	Software Acquired Intangibles	150.9	8.77%	15.5
60	Software Acquired Intangibles - post 2023	14.3	25.00%	2.5
61	Software Developed Intangibles	60.2	10.04%	6.5
62	Software Developed Intangibles - post 2023	14.4	25.00%	2.7
63	CIS Acquired Software	111.0	8.24%	9.1
64	TIS/IT Software	0.0	10.00%	0.0
65	WAMS	89.9	10.74%	9.7
66	Total	1,177.6		99.1
67	Plant held for future use	1.7	3.63% 2.73%	0.0
68	Total	24,857.3	3.59%	892.4

Notes:
(1) Average of the opening and closing plant balances.
(2) Represents forecasted RNG projects in total using a blended rate of assets.

INCOME TAXES

JASON VINAGRE, MANAGER REGULATORY ACCOUNTING
RYAN SMALL, TECHNICAL MANAGER REGULATORY
ERIC ZHANG, MANAGER TAX REPORTING

1. The purpose of this evidence is to provide Enbridge Gas's utility income tax forecasts, to describe the methodology used to calculate utility income tax expense and to request OEB approval of the 2024 Test Year utility income tax forecast.

2. This evidence is organized as follows:
    1. Overview of Utility Income Tax
    2. Legislated Tax Rates
    3. Calculating Utility Taxable Income
    4. Temporary Differences and Harmonization
    5. Calculation of Taxable Income and Supporting Schedules
    6. Enbridge Gas Tax Returns

1. Overview of Utility Income Tax

3. Enbridge Gas's 2024 Test Year Forecast utility income tax expense is $43.8 million[1] /u and is presented in Table 1 along with actual and forecast amounts for 2019 to 2023. The federal and provincial tax rates (15% and 11.5% respectively) have not changed since 2013 and Enbridge Gas assumes the same tax rates to apply in 2022 to 2024 and into the next IR term. Any changes to tax rates or the introduction of changes to income tax legislation during the next IR term not reflected in base rates are expected to be included and disposed of in accordance with the

[1] Excludes taxes on the forecast 2024 Test Year deficiency.

parameters of the Tax Variance Account (TVA).[2] Further details of the TVA are provided at Exhibit 9, Tab 1, Schedule 2.

Table 1
Income Tax Summary

Line No.	Particulars ($ millions)	Utility	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year	
			(a)	(b)	(c)	(d)	(e)	(f)	
1	Income Tax Expense	EGI	59.9	39.2	41.8	33.7	42.1	43.8	/u
2	Federal Tax Rate		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	
3	Provincial Tax Rate		11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	
4	Total Statutory Tax Rate		26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	

4. The utility income tax calculations for the 2024 Test Year, as well as the historical years 2019 to 2020, 2022 Estimate and 2023 Bridge Year are provided at Attachment 1.

5. Utility income tax is recoverable as part of revenue requirement. Utility income tax is calculated by applying the combined legislated federal and provincial tax rates for a given year to taxable utility income. Taxable utility income is calculated by adjusting utility income before interest and taxes for permanent utility tax differences (i.e., expenditures which are not deductible for tax purposes), utility tax timing differences (i.e. depreciation vs. capital cost allowance or CCA), and to reflect deductions for utility interest expense determined through the utility capital structure.

[2] 50% of income tax rate and rule changes and 100% of capital cost allowance (CCA) rate and rule changes will be captured in the TVA.

6. The utility income tax expense reflected in 2024 Test Year revenue requirement reflects the current tax expense forecast for 2024, and therefore excludes future/deferred taxes arising from timing differences. Timing differences will be reflected in utility income tax expense as they reverse and are incorporated into current utility tax expense. This reflects the expectation that income taxes recovered in rates will follow this methodology consistently over time.

2. Legislated Tax Rates

7. A combined federal and provincial tax rate of 26.5% has been assumed for the 2022 Estimate, 2023 Bridge Year and 2024 Test Year based on published legislated tax rates in Canada and Ontario at the time of this filing.[3]

8. As noted previously, impacts of any variances between actual tax rates and rules experienced, versus those assumed in determination of the approved forecast of utility income tax expense, will be captured in the TVA in accordance with its parameters. Please see Exhibit 9, Tab 1, Schedule 2 for the operation of the TVA.

3. Calculating Taxable Utility Income

9. In order to arrive at utility taxable income, utility net income before taxes is first determined by taking Enbridge Gas results determined in accordance with US Generally Accepted Accounting Principles (US GAAP), and then making required utility adjustments (e.g., removal of unregulated amounts, shareholder incentives, etc.). Then, as per applicable tax legislation within the Income Tax Act, utility costs which are non-deductible for tax purposes (temporary and/or permanent) are added

[3] Government of Canada. (2022 May 12). Corporation Tax Rates. Canada Revenue Agency. https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/corporation-tax-rates.html

back to utility net income before taxes and replaced where applicable with deductions allowed for tax purposes.

4. Temporary Differences and Harmonization

10. Adjustments between utility net income before taxes and utility taxable income are made to account for the temporary differences between treatment for accounting purposes under US GAAP and treatment for income tax purposes. These differences will reverse over time resulting in the same deduction after all timing differences reverse.

4.1. Depreciation versus CCA

11. Depreciation for accounting purposes (rate and methodology) differs from depreciation for tax purposes. Depreciation for accounting purposes is added back to net income before taxes and replaced with CCA for tax purposes as a deduction.

12. EGD and Union were aligned in this approach prior to amalgamation in 2019, and since amalgamation Enbridge Gas has continued this treatment and proposes to continue with this treatment.

4.2. Accrued Costs Expensed versus Cash Payments Deductions

13. Costs are generally expensed on an accrual basis for accounting and tax purposes, however certain costs may only be deductible for tax purposes in accordance with the provisions of the Income Tax Act (e.g., when cash payments are made).

Treatment of Pension and Other Post-Employment Benefits (OPEB) Costs

14. Historically, EGD has added back accrual-based pension and OPEB costs (which had previously reduced utility income subject to tax through its inclusion in O&M)

and deducted cash-based pension and OPEB costs, which is consistent with how corporate income taxes are calculated in accordance with the provisions of the Income Tax Act. By contrast, in the determination of utility income subject to tax for Union, there was no adjustment made to taxable income to reflect the difference between accrual-based pension and OPEB costs versus cash-based pension and OPEB costs. As such, accrual-based costs included in utility O&M were deducted in the determination of utility taxable income. Commencing in 2019, Enbridge Gas aligned with the EGD approach because it aligns with how income taxes are calculated in the Enbridge organization, and results in fewer adjustments between Enbridge Gas corporate and Enbridge Gas utility results.

4.3. Costs Capitalized versus Expensed

15. Certain costs are capitalized for accounting purposes but are allowed to be expensed for tax purposes. These cost types and associated treatment for tax purposes are set out below.

Treatment of Overhead Costs Capitalized

16. In accordance with US GAAP (Accounting Standards Codification 980 – Regulated Operations) and acceptable for rate making purposes, Enbridge Gas capitalizes a portion of its annual administrative and general costs to property, plant & equipment as overhead. However, a portion of these overhead costs are allowable as immediate deductions for tax purposes in the year incurred (the portion of capitalized overhead that is directly related to the creation of capital assets is not allowed as an immediate deduction for tax purposes). EGD and Union were aligned in this approach prior to amalgamation in 2019. Enbridge Gas has continued this treatment since 2019 and proposes to continue with this treatment.

Treatment of Interest During Construction (IDC)

17. Historically, EGD did not include a deduction for IDC. Consistent with interest recoverable in utility rates, the interest that was deducted for utility income tax purposes was the amount determined through the utility capital structure. By contrast, in the determination of utility income subject to tax for Union, a deduction for IDC was included, consistent with how corporate income taxes are calculated for tax filing purposes in accordance with the provisions of the Income Tax Act, along with interest determined through the utility capital structure. The Union approach was adopted because it conforms with how Enbridge income taxes are calculated, and results in fewer adjustments between Enbridge Gas corporate and Enbridge Gas utility results. Reflecting IDC as a deduction is also appropriate, as although it is capitalized as part of property plant and equipment, it is not added to undepreciated capital cost (UCC) pools for tax purposes which drive CCA tax deductions (i.e. it is not captured as part of CCA tax deductions). Therefore, reflecting IDC as a deduction allows for the tax benefit to be realized in the year incurred.

<u>5. Calculations of Taxable Income and Supporting Schedules</u>

18. The calculations of utility income tax expense, including the permanent and temporary tax adjustments to convert utility income before tax to utility taxable income, are provided at Attachment 1. The supporting schedules for CCA are provided at Attachment 2 for 2019 to 2024. These attachments provide the details for all applicable historical year actuals, 2022 Estimate, 2023 Bridge Year and 2024 Test Year.

6. Enbridge Gas Tax Returns

19. Copies of the most recent Federal and Provincial tax returns for the tax year 2021 are provided at Exhibit 1, Tab 8, Schedule 1, Attachment 14.

Calculation of Utility Taxable Income and Income Tax Expense
2019 Actual

Line No.	Particulars ($ millions)	Federal	Provincial	Combined
		(a)	(b)	(c)
1	Utility income before income taxes	919.7	919.7	
	Add			
2	Depreciation and amortization	601.7	601.7	
3	Accrual based pension and OPEB costs	49.4	49.4	
4	Other non-deductible items	1.1	1.1	
5	Total Add Back	652.2	652.2	
6	Sub-total	1,571.9	1,571.9	
	Deduct			
7	Capital cost allowance	790.2	790.2	
8	Items capitalized for regulatory purposes	136.0	136.0	
9	Amortization of share/debenture issue expense	(0.4)	(0.4)	
10	Cash based pension and OPEB costs	49.4	49.4	
11	Other	6.4	6.4	
12	Total Deduction	981.6	981.6	
13	Taxable income	590.3	590.3	
14	Income tax rates	15.00%	11.50%	
15	Tax provision excluding interest shield	88.5	67.9	156.4
	Tax shield on interest expense			
16	Rate base	13,139.0		
17	Return component of debt	2.77%		
18	Interest expense	364.4		
19	Combined tax rate	26.50%		
20	Income tax credit			(96.6)
21	Total utility income taxes			59.9

Calculation of Utility Taxable Income and Income Tax Expense
2020 Actual

Line No.	Particulars ($ millions)	Federal (a)	Provincial (b)	Combined (c)
1	Utility income before income taxes	841.1	841.1	
	Add			
2	Depreciation and amortization	618.2	618.2	
3	Accrual based pension and OPEB costs	39.8	39.8	
4	Other non-deductible items	0.5	0.5	
5	Total Add Back	658.5	658.5	
6	Sub-total	1,499.6	1,499.6	
	Deduct			
7	Capital cost allowance	776.8	776.8	
8	Items capitalized for regulatory purposes	143.5	143.5	
9	Amortization of share/debenture issue expense	0.3	0.3	
10	Cash based pension and OPEB costs	57.7	57.7	
11	Other	(2.8)	(2.8)	
12	Total Deduction	975.5	975.5	
13	Taxable income	524.1	524.1	
14	Income tax rates	15.00%	11.50%	
15	Tax provision excluding interest shield	78.6	60.3	138.9
	Tax shield on interest expense			
16	Rate base	13,562.0		
17	Return component of debt	2.77%		
18	Interest expense	376.3		
19	Combined tax rate	26.50%		
20	Income tax credit			(99.7)
21	Total utility income taxes			39.2

Calculation of Utility Taxable Income and Income Tax Expense
2021 Actual

Line No.	Particulars ($ millions)	Federal	Provincial	Combined
		(a)	(b)	(c)
1	Utility income before income taxes	884.3	884.3	
	Add			
2	Depreciation and amortization	640.1	640.1	
3	Accrual based pension and OPEB costs	37.6	37.6	
4	Other non-deductible items	0.3	0.3	
5	Total Add Back	678.1	678.1	
6	Sub-total	1,562.4	1,562.4	
	Deduct			
7	Capital cost allowance	829.9	829.9	
8	Items capitalized for regulatory purposes	152.9	152.9	
9	Amortization of share/debenture issue expense	0.4	0.4	
10	Cash based pension and OPEB costs	42.1	42.1	
11	Other	6.3	6.3	
12	Total Deduction	1,031.6	1,031.6	
13	Taxable income	530.8	530.8	
14	Income tax rates	15.00%	11.50%	
15	Tax provision excluding interest shield	79.6	61.0	140.7
	Tax shield on interest expense			
16	Rate base	14,221.6		
17	Return component of debt	2.62%		
18	Interest expense	373.2		
19	Combined tax rate	26.50%		
20	Income tax credit			(98.9)
21	Total utility income taxes			41.8

Calculation of Utility Taxable Income and Income Tax Expense
2022 Estimate

Line No.	Particulars ($ millions)	Federal	Provincial	Combined	
		(a)	(b)	(c)	
1	Utility income before income taxes	923.5	923.5		
	Add				
2	Depreciation and amortization	705.4	705.4		
3	Accrual based pension and OPEB costs	(0.1)	(0.1)		
4	Other non-deductible items	0.3	0.3		
5	Total Add Back	705.5	705.5		
6	Sub-total	1,629.1	1,629.1		
	Deduct				
7	Capital cost allowance	871.1	871.1		
8	Items capitalized for regulatory purposes	195.7	195.7		
9	Amortization of share/debenture issue expense	0.5	0.5		
10	Cash based pension and OPEB costs	35.0	35.0		
11	Other	0.6	0.6		
12	Total Deduction	1,102.8	1,102.8		
13	Taxable income	526.2	526.2		
14	Income tax rates	15.00%	11.50%		
15	Tax provision excluding interest shield	78.9	60.5	139.4	
	Tax shield on interest expense				
16	Rate base	15,101.3			/u
17	Return component of debt	2.64%			
18	Interest expense	399.0			/u
19	Combined tax rate	26.50%			
20	Income tax credit			(105.7)	/u
21	Total utility income taxes			33.7	/u

Calculation of Utility Taxable Income and Income Tax Expense
2023 Bridge Year

Line No.	Particulars ($ millions)	Federal	Provincial	Combined	
		(a)	(b)	(c)	
1	Utility income before income taxes	952.6	952.6		/u
	Add				
2	Depreciation and amortization	725.3	725.3		/u
3	Accrual based pension and OPEB costs	1.8	1.8		/u
4	Other non-deductible items	0.3	0.3		
5	Total Add Back	727.4	727.4		/u
6	Sub-total	1,680.0	1,680.0		/u
	Deduct				
7	Capital cost allowance	892.8	892.8		/u
8	Items capitalized for regulatory purposes	196.6	196.6		
9	Amortization of share/debenture issue expense	0.9	1.8		
10	Cash based pension and OPEB costs	16.1	16.1		/u
11	Other	0.7	0.7		
12	Total Deduction	1,107.0	1,107.0		/u
13	Taxable income	573.0	573.0		/u
14	Income tax rates	15.00%	11.50%		
15	Tax provision excluding interest shield	85.9	65.9	151.8	/u
	Tax shield on interest expense				
16	Rate base	15,640.1			/u
17	Return component of debt	2.65%			
18	Interest expense	413.9			/u
19	Combined tax rate	26.50%			
20	Income tax credit			(109.7)	/u
21	Total utility income taxes			42.1	/u

Calculation of Utility Taxable Income and Income Tax Expense
2024 Test Year

Line No.	Particulars ($ millions)	Federal	Provincial	Combined	
		(a)	(b)	(c)	
1	Utility income before income taxes	783.4	783.4		/u
	Add				
2	Depreciation and amortization	892.0	892.0		/u
3	Accrual based pension and OPEB costs	(1.6)	(1.6)		/u
4	Other non-deductible items	0.3	0.3		
5	Total Add Back	890.7	890.7		/u
6	Sub-total	1,674.1	1,674.1		/u
	Deduct				
7	Capital cost allowance	870.2	870.2		/u
8	Items capitalized for regulatory purposes	200.2	200.2		
9	Amortization of share/debenture issue expense	1.0	1.0		
10	Cash based pension and OPEB costs	16.9	16.9		/u
11	Other	0.6	0.6		
12	Total Deduction	1,088.8	1,088.8		/u
13	Taxable income	585.3	585.3		/u
14	Income tax rates	15.00%	11.50%		
15	Tax provision excluding interest shield	87.8	67.3	155.1	/u
	Tax shield on interest expense				
16	Rate base	16,281.1			/u
17	Return component of debt	2.58%			/u
18	Interest expense	419.9			/u
19	Combined tax rate	26.50%			
20	Income tax credit			(111.3)	/u
21	Total utility income taxes			43.8	/u

Summary of Capital Cost Allowance (CCA)
2019 Actual

Line No.		Particulars ($000s)	UCC at Prior Year	True-up from Filing to Tax Return	UCC At Beginning of Year	Total Additions	Total Additions Qualifying for Accel. CCA	Less: Lessor of Cost or Proceeds	Eligible CCA Additions	Depreciable UCC Balance	Rate (%)	CCA 2019	Ending UCC
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Class												
1	1	Buildings, structures and improvements, services, meters, mains	2,494,243.2	0.0	2,494,243.2	0.0	0.0	0.0	0.0	2,494,243.2	4%	99,769.7	2,394,473.5
2	1	Non-residential building acquired after March 19, 2007	119,482.3	0.0	119,482.3	8,160.0	6,704.0	0.0	10,784.0	130,266.3	6%	7,816.0	119,826.3
3	2	Mains acquired before 1988	183,609.2	0.0	183,609.2	0.0	0.0	0.0	0.0	183,609.2	6%	11,016.5	172,592.6
4	3	Buildings acquired before 1988	3,320.6	0.0	3,320.6	0.0	0.0	0.0	0.0	3,320.6	5%	166.0	3,154.6
5	6	Other buildings	99.1	0.0	99.1	0.0	0.0	0.0	0.0	99.1	10%	9.9	89.2
6	7	Compression equipment acquired after February 22, 2005	668,237.1	0.0	668,237.1	6,305.3	951.9	0.0	4,104.5	672,341.6	15%	100,851.2	573,691.2
7	8	Compression assets, office furniture, equipment	215,612.9	0.0	215,612.9	35,831.9	33,927.8	0.0	51,843.7	267,456.7	20%	53,491.3	197,953.5
8	10	Transportation, computer equipment	33,344.7	0.0	33,344.7	23,018.5	19,868.5	(358.8)	31,198.3	64,543.0	30%	19,362.9	36,641.5
9	12	Computer software, small tools	14,492.8	0.0	14,492.8	36,311.5	27,696.6	0.0	32,004.0	46,496.8	100%	46,496.8	4,307.4
10	13	Leasehold improvements	1,369.9	0.0	1,369.9	0.0	0.0	0.0	0.0	1,369.9	0%	394.8	975.1
11	14.1	Intangibles	5,693.1	0.0	5,693.1	3,829.1	3,476.0	0.0	5,390.5	11,083.6	5%	554.2	8,968.0
12	14.1	Intangibles (pre 2017)	54,108.7	0.0	54,108.7	0.0	0.0	0.0	0.0	54,108.7	7%	3,787.6	50,321.0
13	17	Roads, sidewalk, parking lot or storage areas	593.8	0.0	593.8	0.0	0.0	0.0	0.0	593.8	8%	47.5	546.3
14	38	Heavy work equipment	5,004.0	0.0	5,004.0	4,552.8	4,552.5	(261.0)	6,698.4	11,702.4	30%	3,510.7	5,785.1
15	41	Storage assets	44,737.6	0.0	44,737.6	3,689.4	725.0	0.0	2,569.7	47,307.3	25%	11,826.8	36,600.2
16	45	Computers - Hardware acquired after March 22, 2004	20.7	0.0	20.7	0.0	0.0	0.0	0.0	20.7	45%	9.3	11.4
17	49	Transmission pipeline additions acquired after February 23, 2005	707,092.0	0.0	707,092.0	96,987.0	88,321.7	0.0	136,815.2	843,907.2	8%	67,512.6	736,566.4
18	50	Computers hardware acquired after March 18, 2007	23,869.8	0.0	23,869.8	33,517.2	15,232.3	0.0	31,990.9	55,860.7	55%	30,723.4	26,663.6
19	51	Distribution pipelines acquired after March 18, 2007	4,638,829.7	(357.2)	4,638,472.5	686,369.7	565,879.1	0.0	909,064.0	5,547,536.5	6%	332,852.2	4,991,990.0
20	Total		9,213,761.3	(357.2)	9,213,404.1	938,572.4	767,335.2	(619.8)	1,222,463.2	10,435,867.3		790,199.6	9,361,157.1

Summary of Capital Cost Allowance (CCA)
2020 Actual

Line No.	Particulars ($000s)		UCC at Prior Year	True-up from Filing to Tax Return	UCC At Beginning of Year	Total Additions	Total Additions Qualifying for Accel. CCA	Less: Lessor of Cost or Proceeds	Eligible CCA Additions	Depreciable UCC Balance	Rate (%)	CCA 2020	Ending UCC
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Class												
1	1	Buildings, structures and improvements, services, meters, mains	2,394,473.5	0.0	2,394,473.5	0.0	0.0	0.0	0.0	2,394,473.5	4%	95,778.9	2,298,694.5
2	1	Non-residential building acquired after March 19, 2007	119,826.3	(239.5)	119,586.8	6,968.2	5,562.9	0.0	9,047.0	128,633.8	6%	7,718.0	118,836.9
3	2	Mains acquired before 1988	172,592.6	0.0	172,592.6	0.0	0.0	0.0	0.0	172,592.6	6%	10,355.6	162,237.1
4	3	Buildings acquired before 1988	3,154.6	0.0	3,154.6	0.0	0.0	0.0	0.0	3,154.6	5%	157.7	2,996.9
5	6	Other buildings	89.2	0.0	89.2	0.0	0.0	0.0	0.0	89.2	10%	8.9	80.3
6	7	Compression equipment acquired after February 22, 2005	573,691.2	(793.8)	572,897.3	3,939.1	3,877.4	0.0	5,847.0	578,744.3	15%	86,811.6	490,024.8
7	8	Compression assets, office furniture, equipment	197,953.5	19.8	197,973.3	47,408.8	47,350.8	0.0	71,055.2	269,028.5	20%	53,805.7	191,576.3
8	10	Transportation, computer equipment	36,641.5	494.4	37,136.0	5,493.7	5,493.7	(45.4)	8,217.8	45,353.8	30%	13,606.1	28,978.1
9	12	Computer software, small tools	4,307.4	(3,302.5)	1,004.9	38,276.4	35,233.3	0.0	36,754.9	37,759.8	100%	37,759.8	1,521.5
10	13	Leasehold improvements	975.1	0.0	975.1	0.0	0.0	0.0	0.0	975.1	0%	301.2	673.9
11	14.1	Intangibles	8,968.0	(8.1)	8,959.9	2,223.5	2,115.8	0.0	3,227.6	12,187.5	5%	609.4	10,574.1
12	14.1	Intangibles (pre 2017)	50,321.0	0.0	50,321.0	0.0	0.0	0.0	0.0	50,321.0	7%	3,522.5	46,798.6
13	17	Roads, sidewalk, parking lot or storage areas	546.3	0.0	546.3	0.0	0.0	0.0	0.0	546.3	8%	43.7	502.6
14	38	Heavy work equipment	5,785.1	37.7	5,822.8	12,318.1	11,966.7	0.0	18,125.8	23,948.5	30%	7,184.6	10,956.3
15	41	Storage assets	36,600.2	(1,534.4)	35,065.8	33,436.1	15,915.5	0.0	32,633.6	67,699.4	25%	16,924.8	51,577.1
16	45	Computers - Hardware acquired after March 22, 2004	11.4	0.0	11.4	0.0	0.0	0.0	0.0	11.4	45%	5.1	6.3
17	49	Transmission pipeline additions acquired after February 23, 2005	736,566.4	(220.6)	736,345.9	75,476.4	73,333.8	0.0	111,072.0	847,417.8	8%	67,793.4	744,028.8
18	50	Computers hardware acquired after March 18, 2007	26,663.6	(8,431.4)	18,232.2	12,620.4	4,413.0	0.0	10,723.2	28,955.3	55%	15,925.4	14,927.1
19	51	Distribution pipelines acquired after March 18, 2007	4,991,990.0	(49,634.2)	4,942,355.8	720,116.5	672,294.0	(2.0)	1,032,351.2	5,974,707.0	6%	358,482.4	5,303,987.9
20	Total		9,361,157.1	(63,612.7)	9,297,544.3	958,277.2	877,557.0	(47.4)	1,339,055.2	10,636,599.6		776,795.0	9,478,979.1

Summary of Capital Cost Allowance (CCA)
2021 Actual

Line No.	Particulars ($000s)		UCC at Prior Year	True-up from Filing to Tax Return	UCC At Beginning of Year	Total Additions	Total Additions Qualifying for Accel. CCA	Less: Lessor of Cost or Proceeds	Eligible CCA Additions	Depreciable UCC Balance	Rate (%)	CCA 2021	Ending UCC
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Class												
1	1	Buildings, structures and improvements, services, meters, mains	2,298,694.5	0.0	2,298,694.5	0.0	0.0	0.0	0.0	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	0.0	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	0.0	0.0	0.0	0.0	162,222.2	6%	9,733.3	152,488.9
4	3	Buildings acquired before 1988	2,996.9	0.0	2,996.9	0.0	0.0	0.0	0.0	2,996.9	5%	149.8	2,847.0
5	6	Other buildings	80.3	(2.0)	78.3	0.0	0.0	0.0	0.0	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	0.0	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	17,588.1	17,588.1	0.0	26,382.2	217,767.7	20%	43,553.5	165,420.1
8	10	Transportation, computer equipment	28,978.1	42.8	29,020.9	8,474.7	8,474.7	(86.2)	12,668.9	41,603.6	30%	12,481.1	24,928.3
9	12	Computer software, small tools	1,521.5	(1,521.5)	0.0	60,610.1	57,567.0	0.0	59,088.6	59,088.6	100%	59,088.6	1,521.5
10	13	Leasehold improvements	673.9	(110.1)	563.8	0.0	0.0	0.0	0.0	563.8	0%	212.1	351.7
11	14	Intangibles	10,574.1	(4.9)	10,569.1	2,802.8	2,704.6	0.0	4,106.0	14,675.1	5%	733.8	12,638.2
12	14.1	Intangibles (pre 2017)	46,798.6	0.0	46,798.6	0.0	0.0	0.0	0.0	46,798.6	7%	3,275.9	43,522.7
13	17.0	Roads, sidewalk, parking lot or storage areas	502.6	0.0	502.6	0.0	0.0	0.0	0.0	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	0.0	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	0.0	80,529.3	135,813.6	25%	33,953.4	78,076.1
16	45	Computers - Hardware acquired after March 22, 2004	6.3	0.0	6.3	0.0	0.0	0.0	0.0	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	0.0	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	23,333.6	17,371.7	0.0	29,038.5	44,281.6	55%	24,354.9	14,221.8
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	0.0	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	1,121,976.0	1,105,209.7	(86.2)	1,637,371.1	11,102,469.2		829,932.6	9,757,141.6

Summary of Capital Cost Allowance (CCA)
2022 Estimate

Line No.	Particulars ($000s)		UCC at Prior Year	True-up from Filing to Tax Return	UCC At Beginning of Year	Total Additions	Total Additions Qualifying for Accel. CCA	Less: Lessor of Cost or Proceeds	Eligible CCA Additions	Depreciable UCC Balance	Rate (%)	CCA 2022	Ending UCC
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Class												
1	1	Buildings, structures and improvements, services, meters, mains	2,206,746.7	0.0	2,206,746.7	0.0	0.0	0.0	0.0	2,206,746.7	4%	88,269.9	2,118,476.9
2	1	Non-residential building acquired after March 19, 2007	140,204.4	15.0	140,219.4	32,894.5	32,894.5	0.0	49,341.8	189,561.2	6%	11,373.7	161,740.2
3	2	Mains acquired before 1988	152,488.9	0.0	152,488.9	0.0	0.0	0.0	0.0	152,488.9	6%	9,149.3	143,339.5
4	3	Buildings acquired before 1988	2,847.0	0.0	2,847.0	0.0	0.0	0.0	0.0	2,847.0	5%	142.4	2,704.7
5	6	Other buildings	70.5	0.0	70.5	0.0	0.0	0.0	0.0	70.5	10%	7.0	63.4
6	7	Compression equipment acquired after February 22, 2005	421,057.3	(9.2)	421,048.1	11,506.3	11,506.3	0.0	17,259.5	438,307.5	15%	65,746.1	366,808.2
7	8	Compression assets, office furniture, equipment	165,420.1	(1,295.5)	164,124.6	92,822.2	92,822.2	0.0	139,233.3	303,358.0	20%	60,671.6	196,275.3
8	10	Transportation, computer equipment	24,928.3	2,705.2	27,633.5	21,282.9	21,282.9	0.0	31,924.4	59,557.9	30%	17,867.4	31,049.1
9	12	Computer software, small tools	1,521.5	(1,521.5)	0.0	53,722.6	53,279.2	0.0	53,500.9	53,500.9	100%	53,500.9	221.7
10	13	Leasehold improvements	351.7	0.0	351.7	0.0	0.0	0.0	0.0	351.7	0%	212.1	139.6
11	14	Intangibles	12,638.2	(4.9)	12,633.3	2,003.6	2,003.6	0.0	3,005.4	15,638.7	5%	781.9	13,855.0
12	14.1	Intangibles (pre 2017)	43,522.7	0.0	43,522.7	0.0	0.0	0.0	0.0	43,522.7	7%	3,046.6	40,476.1
13	17.0	Roads, sidewalk, parking lot or storage areas	462.4	0.0	462.4	0.0	0.0	0.0	0.0	462.4	8%	37.0	425.4
14	38	Heavy work equipment	9,072.7	1,548.6	10,621.4	3,463.6	3,463.6	0.0	5,195.5	15,816.8	30%	4,745.0	9,340.0
15	41	Storage assets	78,076.1	(5,906.6)	72,169.5	29,472.7	26,340.0	0.0	41,076.4	113,245.9	25%	28,311.5	73,330.8
16	45	Computers - Hardware acquired after March 22, 2004	3.4	0.0	3.4	0.0	0.0	0.0	0.0	3.4	45%	1.6	1.9
17	49	Transmission pipeline additions acquired after February 23, 2005	758,627.8	113.3	758,741.1	64,659.6	64,659.6	0.0	96,989.4	855,730.5	8%	68,458.4	754,942.3
18	50	Computers hardware acquired after March 18, 2007	14,221.8	(5,971.1)	8,250.7	33,049.3	32,541.7	0.0	49,066.4	57,317.0	55%	31,524.4	9,775.6
19	51	Distribution pipelines acquired after March 18, 2007	5,724,879.9	(12,598.4)	5,712,281.6	939,090.0	939,090.0	0.0	1,408,634.9	7,120,916.5	6%	427,255.0	6,224,116.5
20	Total		9,757,141.6	(22,925.1)	9,734,216.5	1,283,967.5	1,279,883.7	0.0	1,895,227.9	11,629,444.4		871,101.7	10,147,082.3

Summary of Capital Cost Allowance (CCA)
2023 Bridge Year

Line No.	Class	Particulars ($000s)	UCC at Prior Year (a)	Opening Balance Adjustments (b)	UCC At Beginning of Year (c)	Total Additions (d)	Total Additions Qualifying for Accel. CCA (e)	Less: Lessor of Cost or Proceeds (f)	Eligible CCA Additions (g)	Depreciable UCC Balance (h)	Rate (%) (i)	CCA 2023 (j)	Ending UCC (k)	
1	1	Buildings, structures and improvements, services, meters, mains	2,118,476.9	0.0	2,118,476.9	0.0	0.0	0.0	0.0	2,118,476.9	4%	84,739.1	2,033,737.8	
2	1	Non-residential building acquired after March 19, 2007	161,740.2	0.0	161,740.2	27,868.4	27,868.4	0.0	41,802.6	203,542.8	6%	12,212.6	177,396.1	/u
3	2	Mains acquired before 1988	143,339.5	0.0	143,339.5	0.0	0.0	0.0	0.0	143,339.5	6%	8,600.4	134,739.2	
4	3	Buildings acquired before 1988	2,704.7	0.0	2,704.7	0.0	0.0	0.0	0.0	2,704.7	5%	135.2	2,569.4	
5	6	Other buildings	63.4	0.0	63.4	0.0	0.0	0.0	0.0	63.4	10%	6.3	57.1	
6	7	Compression equipment acquired after February 22, 2005	366,808.2	0.0	366,808.2	6,582.3	6,582.3	0.0	9,873.5	376,681.7	15%	56,502.3	316,888.3	/u
7	8	Compression assets, office furniture, equipment	196,275.3	0.0	196,275.3	77,986.2	77,986.2	0.0	116,979.2	313,254.5	20%	62,650.9	211,610.5	/u
8	10	Transportation, computer equipment	31,049.1	0.0	31,049.1	15,898.6	15,898.6	0.0	23,847.9	54,896.9	30%	16,469.1	30,478.6	/u
9	12	Computer software, small tools	221.7	0.0	221.7	43,112.9	43,112.9	0.0	43,112.9	43,334.6	100%	43,334.6	0.0	
10	13	Leasehold improvements	139.6	0.0	139.6	0.0	0.0	0.0	0.0	139.6	0%	107.8	31.9	
11	14	Intangibles	13,855.0	(386.2)	13,468.8	5,132.0	5,132.0	0.0	7,697.9	21,166.8	5%	1,058.3	17,542.5	/u
12	14.1	Intangibles (pre 2017)	40,476.1	0.0	40,476.1	0.0	0.0	0.0	0.0	40,476.1	7%	2,833.3	37,642.8	
13	17.0	Roads, sidewalk, parking lot or storage areas	425.4	0.0	425.4	0.0	0.0	0.0	0.0	425.4	8%	34.0	391.4	
14	38	Heavy work equipment	9,340.0	0.0	9,340.0	3,572.9	3,572.9	0.0	5,359.3	14,699.2	30%	4,409.8	8,503.0	/u
15	41	Storage assets	73,330.8	0.0	73,330.8	58,134.6	58,134.6	0.0	87,201.8	160,532.6	25%	40,133.2	91,332.2	/u
16	45	Computers - Hardware acquired after March 22, 2004	1.9	0.0	1.9	0.0	0.0	0.0	0.0	1.9	45%	0.9	1.0	
17	49	Transmission pipeline additions acquired after February 23, 2005	754,942.3	0.0	754,942.3	187,685.0	187,685.0	0.0	281,527.6	1,036,469.8	8%	82,917.6	859,709.7	/u
18	50	Computers hardware acquired after March 18, 2007	9,775.6	0.0	9,775.6	22,931.6	22,931.6	0.0	34,397.4	44,173.0	55%	24,295.1	8,412.1	/u
19	51	Distribution pipelines acquired after March 18, 2007	6,224,116.5	(62,936.2)	6,161,180.4	918,626.3	918,626.3	0.0	1,377,939.5	7,539,119.8	6%	452,347.2	6,627,459.5	/u
20		Total	10,147,082.3	(63,322.3)	10,083,759.9	1,367,530.7	1,367,530.7	0.0	2,029,739.6	12,113,499.5		892,787.6	10,558,503.0	/u

Summary of Capital Cost Allowance (CCA)
2024 Test Year

Line No.	Particulars ($000s)		UCC at Prior Year	Asset Harmonization Adjustments	UCC At Beginning of Year	Total Additions	Total Additions Qualifying for Accel. CCA	Less: Lessor of Cost or Proceeds	Eligible CCA Additions	Depreciable UCC Balance	Rate (%)	CCA 2024	Ending UCC	
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Class													
1	1	Buildings, structures and improvements, services, meters, mains	2,033,737.8	19,520.9	2,053,258.7	0.0	0.0	0.0	0.0	2,053,258.7	4%	82,130.3	1,971,128.4	
2	1	Non-residential building acquired after March 19, 2007	177,396.1	0.0	177,396.1	9,895.4	9,895.4	0.0	9,895.4	187,291.5	6%	11,237.5	176,054.0	/u
3	2	Mains acquired before 1988	134,739.2	(4,212.9)	130,526.2	0.0	0.0	0.0	0.0	130,526.2	6%	7,831.6	122,694.7	
4	3	Buildings acquired before 1988	2,569.4	0.0	2,569.4	0.0	0.0	0.0	0.0	2,569.4	5%	128.5	2,441.0	
5	6	Other buildings	57.1	0.0	57.1	0.0	0.0	0.0	0.0	57.1	10%	5.7	51.4	
6	7	Compression equipment acquired after February 22, 2005	316,888.3	0.0	316,888.3	3,523.5	3,523.5	0.0	3,523.5	320,411.9	15%	48,061.8	272,350.1	/u
7	8	Compression assets, office furniture, equipment	211,610.5	2,048.9	213,659.5	64,116.7	64,116.7	0.0	64,116.7	277,776.1	20%	55,555.2	222,220.9	/u
8	10	Transportation, computer equipment	30,478.6	(152.7)	30,325.9	22,691.9	22,691.9	0.0	22,691.9	53,017.8	30%	15,905.3	37,112.5	/u
9	12	Computer software, small tools	0.0	0.0	0.0	40,082.3	40,082.3	0.0	40,082.3	40,082.3	100%	40,082.3	0.0	
10	13	Leasehold improvements	31.9	(0.0)	31.9	0.0	0.0	0.0	0.0	31.9	0%	3.4	28.4	
11	14	Intangibles	17,542.5	0.0	17,542.5	2,943.2	2,943.2	0.0	2,943.2	20,485.6	5%	1,024.3	19,461.3	/u
12	14.1	Intangibles (pre 2017)	37,642.8	0.0	37,642.8	0.0	0.0	0.0	0.0	37,642.8	7%	2,635.0	35,007.8	
13	17.0	Roads, sidewalk, parking lot or storage areas	391.4	0.0	391.4	0.0	0.0	0.0	0.0	391.4	8%	31.3	360.1	
14	38	Heavy work equipment	8,503.0	0.0	8,503.0	4,765.6	4,765.6	0.0	4,765.6	13,268.7	30%	3,980.6	9,288.1	/u
15	41	Storage assets	91,332.2	(1,332.0)	90,000.2	70,903.1	70,903.1	0.0	70,903.1	160,903.3	25%	40,225.8	120,677.5	/u
16	45	Computers - Hardware acquired after March 22, 2004	1.0	0.0	1.0	0.0	0.0	0.0	0.0	1.0	45%	0.5	0.6	
17	49	Transmission pipeline additions acquired after February 23, 2005	859,709.7	307,517.8	1,167,227.5	122,368.1	122,368.1	0.0	122,368.1	1,289,595.5	8%	103,167.6	1,186,427.9	/u
18	50	Computers hardware acquired after March 18, 2007	8,412.1	(41.1)	8,370.9	29,188.7	29,188.7	0.0	29,188.7	37,559.7	55%	20,657.8	16,901.9	/u
19	51	Distribution pipelines acquired after March 18, 2007	6,627,459.5	(324,630.4)	6,302,829.1	990,068.3	990,068.3	0.0	990,068.3	7,292,897.4	6%	437,573.8	6,855,323.6	/u
20	Total		10,558,503.0	(1,281.5)	10,557,221.5	1,360,546.8	1,360,546.8	0.0	1,360,546.8	11,917,768.3		870,238.5	11,047,529.9	/u

PROPERTY TAXES

ROB FORD, SPECIALIST CANADIAN PROPERTY TAX

RUTH SWAN, SPECIALIST CANADIAN PROPERTY TAX

1. The purpose of this evidence is to request approval of Enbridge Gas's utility forecast of its regulated property tax expense for the 2024 Test Year which is $127.2 million.

2. This evidence is organized as follows:
    1. Summary of Property Taxes
    2. Opening Base
    3. Mains and Service Growth
    4. Special/Major Projects
    5. Inflation

1. Summary of Property Taxes

3. Table 1 provides an overview of the utility property taxes for Enbridge Gas for the 2019 to 2021 historical years, 2022 Estimate, 2023 Bridge Year and 2024 Test Year.

Table 1
Property Tax Summary

Line No.	Particulars ($ millions)	2019 Actual	2020 Actual	2021 Actual	2022 Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)	(d)	(e)	(f)
1	Regulated Property Tax	121.4	124.6	116.2	118.5	122.5	127.2

4. The year-over-year variance between 2019 and 2020 was attributable to inflation, mains and service growth, and special/major projects including the Kingsville Transmission Reinforcement Pipeline Project, Chatham Kent Rural Pipeline Expansion Project, and Stratford Transmission Pipeline Project. For 2020 and 2021 the variance is attributable to the reduction in the business education tax (BET) rates applicable to commercial, industrial and pipeline properties. Ontario property tax rates are typically comprised of municipal and provincial BET rates. Up until 2021 the BET rates varied across the province, some as high as 1.25%. In 2021 the Ministry of Finance reduced the BET rates in Ontario on commercial, industrial and pipeline properties to 0.88% by way of Ontario Regulation 46/21, resulting in a significant decrease.

2. Opening Base

5. The 2022 Estimate for property taxes is the base used in establishing the estimated property taxes for the 2024 Test Year. The utility property tax forecast is $118.5 million for the 2022 Estimate. This is adjusted for mains and service growth, special/major projects, and inflation to arrive at the property tax estimate for the 2024 Test Year. Table 2 presents the property tax forecast for 2022 to 2024.

Table 2
Property Tax Forecast

Line No.	Particulars ($ millions)	2022 Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)
1	Opening Base	117.2	120.2	124.4
2	Mains and Service Growth	1.3	1.0	0.9
3	Special and Major Projects	0.5	0.3	1.3
4	Inflation	1.2	2.9	2.7
5	Subtotal	120.2	124.4	129.3
6	Less: Unregulated Storage Taxes	(1.8)	(1.9)	(2.1)
7	Total	118.5	122.5	127.2

Notes:
(1) Special and Major Projects includes Leave to Construct projects, major land acquisitions/dispositions and redevelopment.
(2) 2024 unregulated storage taxes include the storage and general plant assets allocation for shared facilities for non-utility usage. This reflects the proposed methodology as provided at Exhibit 1, Tab 13, Schedule 2.

6. The opening base 2022 property tax forecast is based off the annual property taxes paid in the prior year. This forecast is adjusted for growth, inflation and special/major projects for the 2022 Estimate, 2023 Bridge Year and 2024 Test Year. The sections that follow provide an explanation of how these factors are captured in the 2022 Estimate, 2023 Bridge Year and 2024 Test Year utility property tax forecast.

3. Mains and Service Growth

7. Mains and service growth is based on an annual report Enbridge Gas provides to the Municipal Property Assessment Corporation (Assessment Corporation) as set forth in accordance with Section 25 (2) (2) of the Assessment Act, R.S.O., C. A.31. which requires a pipeline company to notify the assessment corporation of the age,

length and diameter of all of its pipelines located on January 1 of that year, on or before March 1 of every year. The Assessment Corporation compares this report to the prior years and differences are assessed accordingly, pursuant to Section 33 (1) of the Assessment Act, R.S.O., C. A.31.

4. Special/Major Projects

8. The special and major projects referenced in Table 3 have been included based on their significance to impact Enbridge Gas's utility property tax. Notable projects provided at Exhibit 2, Tab 5, Schedule 1 have been included where significant property taxes are attributable. Property tax forecasts for special or major projects are separately calculated by forecasting the assessment base and multiplying this base by the tax rate(s) for the specific jurisdictions where these projects are located, adjusted for inflation. Major land acquisitions/sales and property redevelopment are also considered.

Table 3
Property Tax Special & Major Projects Forecast

Line No.	Particulars ($ millions)	2022 Estimate	2023 Bridge Year	2024 Test Year
		(a)	(b)	(c)
1	Compressor Stations	0.0	0.2	0.4
2	Distribution Pipe	0.3	0.2	0.0
3	Transmission Pipe	0.0	0.2	0.9
4	Real Estate & Workplace Services	0.2	(0.3)	0.0
5	Total	0.5	0.3	1.3

Notes:
(1) Includes Dawn to Corunna Replacement Project.
(2) Includes London Line, NPS 20 Lakeshore, and Kirkland Lake Replacements.
(3) Includes Panhandle Regional Expansion Project.
(4) Includes SMOC/Coventry Facility consolidation, Station B New Building, Kennedy Road Expansion, Toronto Operations Centre, Schmon Parkway.

9. An inflation escalation rate of 1% was used for the 2022 Estimate. This escalation rate was based on an internal analysis of pipeline tax impacts for the 2016 to 2020 taxation years. The 2021 taxation year was excluded due to the business education tax reductions implemented by the Ministry of Finance in 2021.

<u>5. Inflation</u>

10. The 2023 and 2024 utility property tax forecast has been adjusted for the inflation rate of 2.4% and 2.2 % respectively for the Bridge Year and Test Year as provided in the Economic and Financial Assumptions provided at Exhibit 3, Tab 2, Schedule 4.

PARKWAY DELIVERY OBLIGATION &
PARKWAY DELIVERY COMMITMENT CREDIT
MAX HAGERMAN, MANAGER, CAPACITY MANAGEMENT & UTILIZATION
AMY MIKHAILA, MANAGER, RATE DESIGN

1. This evidence supports Enbridge Gas's request for approval of an updated Parkway Delivery Obligation (PDO) Framework and approval of the 2024 Parkway Delivery Commitment Incentive (PDCI) forecast cost of $17.6 million. The proposed PDO Framework reflects a harmonized approach to the PDO and the PDCI for the amalgamated utility, effective January 1, 2024.

2. If approved by the OEB in this Application, the proposed PDO Framework will replace the Settlement Framework for Reduction of Parkway Delivery Obligation (PDO Settlement Framework) that was approved by the OEB in Union's 2014 Rates proceeding[1]. The PDO Framework is intended to be used as a reference document for the PDO reduction, PDCI payment and PDO reporting. Enbridge Gas is not proposing to change the intent of the original PDO Settlement Agreement as there continues to be an operational requirement for customers to deliver gas at Parkway.

3. This evidence also provides a response to the OEB directive from the MAADs proceeding[2] to track actual costs and amounts recovered through rates related to PDO during the deferred rebasing term.

[1] EB-2013-0365, Settlement Framework, Appendix B, June 3, 2014.
[2] EB-2017-0306/EB-2017-0307.

4. This evidence is organized as follows:
    1. PDO Overview
    2. Proposed PDO Framework
    3. 2024 PDO Forecast
    4. PDO Directive Reporting

1. PDO Overview

5. As part of its 2014 Rates proceeding[3], Union reached an agreement with parties on the reduction of the PDO and payment of a PDCI through the PDO Settlement Framework with an end-date of December 31, 2018. The mechanism was subsequently extended through Enbridge Gas's 2019 to 2023 deferred rebasing term following the OEB's MAADs Decision[4].

6. The intent of the PDO Settlement Framework was to address the inequity in which the delivery of gas required by the utility at Parkway was achieved. At the time, several direct purchase (DP) customers were contractually required to deliver some or all their daily contract quantity (DCQ)[5] at Parkway, at their own expense, in order for the utility to operate its system. Consequently, DP customers with a PDO conferred a benefit on all users of the Dawn Parkway System because the system capacity was less than would otherwise be required. The parties agreed that the PDO should be permanently reduced by shifting customer's obligated DCQ from Parkway to Dawn and the payment of a PDCI should be made for any continuing obligated DCQ deliveries at Parkway.

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[3] EB-2013-0365.
[4] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.
[5] DCQ is the fixed daily quantity of gas to be delivered by DP customers at an obligated delivery point, every day of the year. A customer's DCQ is determined by dividing a forecast of consumption at the associated point(s) of consumption by the number of days in the term, typically 365 days.

7. The guiding principle of the PDO Settlement Framework was to keep Union whole rather than to enhance or reduce its earnings during the IR term[6]. As such, the costs of the PDO shift and PDCI have been and continue to be updated in base rates annually. Any variance associated with timing differences are recorded in the Parkway Obligation Rate Variance Account (PORVA).

8. To date, Enbridge Gas has not been able to shift the obligated deliveries of all customers from Parkway to Dawn due to the continued operational requirement for customers to deliver gas at Parkway. Rather, the PDO quantities have been increasing each year because of increased DCQ requirements for the Union South rate zone customers on the Dawn Parkway System. The DP customers who continue to deliver gas at Parkway receive the PDCI.

9. In the 2021 Rates proceeding[7], Enbridge Gas agreed with parties to file evidence in its 2022 Rates proceeding detailing what pipeline, non-pipeline and market-based alternative approaches Enbridge Gas has considered in order to determine whether it is cost-effective to eliminate or reduce the PDO and/or PDCI for 2022 and future years.[8] As part of the response to this commitment, Enbridge Gas issued an RFP for market-based solutions that could potentially be used to reduce the PDO. Enbridge Gas received interest to the RFP and implemented a market-based solution to reduce the PDO by 26.5 TJ/d as of November 1, 2022.

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[6] The PDO Settlement Framework was in place during Union's 2014 to 2018 IR term and was subsequently extended through Enbridge Gas's 2019 to 2023 deferred rebasing term.
[7] EB-2020-0095.
[8] Ibid, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, October 6, 2020, p.10.

2. Proposed PDO Framework

10. Enbridge Gas is proposing to continue with the PDO reduction and PDCI payment as outlined in the proposed PDO Framework, provided at Attachment 1, as is reasonable for the efficient management of the Dawn Parkway System capacity. The proposed PDO Framework will replace the current PDO Settlement Framework effective January 1, 2024 and serve as a reference document for the PDO reduction, PDCI payment and PDO reporting for the next IR term and beyond.

11. The PDO Framework will also incorporate the rate design and service harmonization changes proposed in this Application.

12. The following sections of evidence describe the proposed changes from the original PDO Settlement Framework:
    - 2.1 Rates and Service Harmonization
    - 2.2 PDO Reduction
    - 2.3 Annual Updates and PDO Reporting

2.1. Rates and Service Harmonization

13. Enbridge Gas is proposing changes to harmonize rates and service offerings for the amalgamated utility as part of this Application. There are four rate design proposals that impact the PDO Framework that are described in this section of evidence, including:
    1. Expand PDCI Payment
    2. Seasonal DCQ PDCI Payment
    3. Remove Sales Service PDCI Payment
    4. Allocation of PDCI Payment Costs

Expand PDCI Payment

14. Enbridge Gas is proposing to expand the PDO and PDCI offering to customers located in the EGD rate zone who currently are contractually obligated to deliver gas at the Enbridge CDA[9]. These customers provide a similar system benefit as the DP customers in the Union South rate zone with a PDO, as they have the option to deliver gas to Dawn, which would otherwise increase the Dawn Parkway System demand. Similar to Parkway, the Enbridge CDA is located at the east end of the Dawn Parkway System and for the purposes of this evidence, Parkway and the Enbridge CDA will be collectively referred to as Parkway.

15. As part of the current service offerings in the EGD rate zone, Enbridge Gas offers a bundled DP service option to deliver gas at Parkway as part of the Ontario T-Service. These customers currently do not pay gas supply transportation charges to transport gas to Parkway as they deliver their gas directly to Parkway. Enbridge Gas is proposing to harmonize the rate design for DP customers located in the Enbridge CDA and the Union South rate zone, such that they pay common transportation rates. To recognize the system benefit of delivering gas to Parkway, these customers will receive a PDCI payment as an offset to the gas supply transportation charges. Please see Exhibit 8, Tab 2, Schedule 2 for a description of the proposed rate design for gas supply transportation charges.

16. Enbridge Gas has incorporated the Ontario T-Service customers in the EGD rate zone that deliver gas to the Enbridge CDA in the PDO forecast and in the total

[9] The Enbridge CDA is an interconnect between TransCanada and Enbridge Gas located at the east end of the Dawn Parkway System.

PDCI cost, effective January 1, 2024. Currently, there are approximately 36 customers located in the EGD rate zone with 46 TJ/d of PDO.

Seasonal DCQ PDCI Payment

17. Enbridge Gas is proposing to provide PDCI payments for customers with a seasonal DCQ based on their winter DCQ. Enbridge Gas currently offers a seasonal DCQ option for seasonal service in the EGD rate zone and is proposing to offer a similar seasonal service across the franchise area, as part of the service harmonization proposals, provided at Exhibit 8, Tab 4, Schedule 2 and Exhibit 8, Tab 4, Schedule 3. If a bundled DP customer selects a seasonal DCQ and has a PDO, the customer will receive the PDCI payment for their winter Parkway DCQ quantity through the year, as the customer's higher summer Parkway DCQ is not providing the same peak day benefit as customers that have a PDO during the winter months from December to March.

Remove Sales Service PDCI Payment

18. Enbridge Gas is proposing to no longer apply a PDCI credit to sales service customers. Under the current rate design, the incremental transportation costs to deliver gas to Parkway are recovered from sales service customers located in the Union South rate zone and offset by the PDCI to recognize the benefit of gas supply arriving at Parkway. In the proposed rate design, the transportation costs to deliver gas to all delivery areas, including Parkway, are directly recovered from both sales service and DP customers through gas supply transportation charges, thus eliminating the need for the sales service PDCI. By including the incremental costs to transport gas to Parkway in gas supply transportation charges, there is no longer a need to credit sales service customers for these costs through the PDCI.

Allocation of PDCI Payment Costs

19. Enbridge Gas is proposing to change the allocation of the PDCI payment costs within the cost allocation study to ensure the allocation reflects the use of the Dawn Parkway System and the total system benefit provided by the PDO. In accordance with the PDO Settlement Framework, the cost of the PDCI payment is currently allocated to Union South in-franchise rate classes in proportion to firm design day demands on the Dawn Parkway System. Enbridge Gas is proposing to change the allocation of the PDCI payment costs to include both in-franchise and ex-franchise rate classes, consistent with the allocation of the Dawn Parkway transmission demand costs. A description of the proposed cost allocation methodology is provided at Exhibit 7, Tab 1, Schedule 4.

2.2. *2024 PDO Reduction*

20. As part of the PDO Settlement Framework[10], Union intended to use Dawn to Kirkwall turnback as the primary method to reduce the PDO. Although Dawn to Kirkwall turnback may still be used to facilitate a PDO reduction, there are insufficient Dawn to Kirkwall contracts remaining to provide a complete PDO reduction. As such, Enbridge Gas has implemented a market-based solution in 2022 and will consider other means to reduce the PDO.

21. Enbridge Gas is proposing to update the PDO Framework to include the other means available to facilitate a PDO reduction, which includes using capacity turned back on the Dawn Parkway System (in addition to Dawn to Kirkwall turnback), infrastructure construction, or by other market opportunities, provided the alternative is available, operational, and financially viable. At its sole discretion, Enbridge Gas would consider the use of Dawn Parkway System turnback to reduce

[10] EB-2013-0365, Settlement Framework, Appendix B, June 3, 2014.

the PDO provided any quantities turned back were first offered to the market through an existing capacity open season. The priority for using excess Dawn Parkway System capacity is to serve contracted long-term demands.

22. Enbridge Gas will also continue to seek and implement market-based solutions to reduce the PDO, recognizing that market-based solutions can be difficult to contract due to the term and the required conditions of service. Market-based solutions can also be considered short-term as cost and availability can vary. There is currently one market-based solution in place for a firm exchange service between Dawn and Parkway, which allows Enbridge Gas to reduce the PDO, as described in Section 1. Enbridge Gas will annually review potential market-based solutions to reduce the PDO and report on alternatives considered in annual deferral and variance account proceedings.

2.3. Annual Updates and PDO Reporting

23. Enbridge Gas is proposing to no longer update base rates annually for changes in the PDO costs. Enbridge Gas will continue to update the PDCI rate to reflect the approved Rate M12 Dawn to Parkway toll including fuel costs as part of the annual rate case proceeding to ensure DP customers with a PDO receive the appropriate PDCI payment.

24. Any variances between the amount included in base rates and the actual costs will be recorded in a new deferral account and disposed of as part of the annual deferral and variance account proceeding. Enbridge Gas is proposing to update the purpose of the existing variance account (PORVA) and replace it with the Parkway Delivery Obligation Variance Account (PDOVA), a new Enbridge Gas variance account, effective January 1, 2024. The PDOVA will capture cost variances

between the PDO reduction and PDCI payment costs in rates and actual costs incurred. This proposed approach is consistent with recording cost variances in deferral and variance accounts over the IR term and maintains the guiding principle of the PDO Framework to keep the utility whole. A description of the proposed variance account is provided at Exhibit 9, Tab 1, Schedule 2. The proposed accounting order is provided at Exhibit 9, Tab 1, Schedule 1, Attachment 3.

25. As Enbridge Gas will no longer update the PDO costs in the annual rate case proceeding, Enbridge Gas is proposing to provide annual updates on the PDO reduction and PDCI payment costs as part of the annual deferral and variance account proceedings. As part of the evidence, Enbridge Gas will also include details regarding:
    a) Capacity that could become available in the following two years that could be used to further reduce the PDO;
    b) Potential market-based solution alternatives to reduce the PDO;
    c) Forecast PDO volumes for the two years following the current year; and
    d) The measures considered and used to reduce the PDO in the current year.

3. 2024 PDO Forecast

26. As described at Section 1, Enbridge Gas has not been able to shift the deliveries of all customers from Parkway to Dawn due to the continued operational need for gas deliveries at Parkway as well as the limited amount of remaining Dawn to Kirkwall capacity available for turnback. The quantity of gas delivered to Parkway has increased each year because of increased demands on the Dawn Parkway System. On a longer-term basis, Enbridge Gas anticipates the PDO will continue to increase each year through the IR term as efforts made by the Company to reduce the PDO will be offset by customer growth.

27. The DP customer PDO forecast on November 1, 2024 is 270 TJ/d. The annual PDO forecast for the 2024 Test Year is an average of 261 TJ/d.[11] The PDO forecast includes the addition of approximately 46 TJ/d for DP customers in the EGD rate zone with a PDO.

28. The forecast cost of the PDCI included in the 2024 Test Year Forecast is $17.6 million based on the 2023 Forecast M12 toll and compressor fuel rates at April 2022 QRAM, including market-based solutions costs. The PDCI cost will be updated for the proposed 2024 M12 Dawn to Parkway toll and compressor fuel costs as part of rate design evidence provided at Exhibit 8, Tab 1, Schedule 1.

29. The forecast costs include the market-based solution, which has facilitated a PDO shift of approximately 26.5 TJ/d from approximately 140 DP customers (of the potential 497 DP customers), effective November 1, 2022. This alternative resulted in a net decrease to the PDCI cost of $0.6 million in 2024. There is no other PDO shift forecast using a market-based solution in 2024.

<u>4. PDO Directive Reporting</u>

30. In the MAADs Decision, the OEB required Enbridge Gas to track actual costs and amounts recovered through rates related to the PDO during the deferred rebasing term.[12] At the time, the OEB determined that there was insufficient evidence to determine whether ratepayers are paying twice for the same capacity as a result of the implementation of the PDO.

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[11] The difference between the PDO forecast of 270 TJ/d on November 1, 2024 and the annual PDO forecast of 261 TJ/d is a result of seasonal DCQ requirements.
[12] EB-2017-0305/0306, OEB Decision and Order, August 30, 2018, p.49.

31. The PDO costs included in rates during the deferred rebasing term appropriately recover the PDO costs incurred and accordingly, ratepayers have not paid twice for the same capacity.

4.1. PDO Costs in Rates and Actual PDO Costs

32. As shown in Table 1, the actual PDO costs incurred by the Company are higher than the PDO costs included in rates for each available year of the deferred rebasing term, resulting in a revenue shortfall for the Company. The detailed calculations supporting the amounts in Table 1 are provided at Attachment 2.

Table 1
Comparison of PDO Costs in Rates and Actual PDO Costs

Line No.	Particulars ($000s)	Actual 2019	Actual 2020	Actual 2021	Estimate 2022 (1)
		(a)	(b)	(c)	(d)
	PDO Costs in Rates				
1	PDO Demand Costs	10,956	11,117	11,273	11,391
2	PDO Fuel Costs	1,640	1,404	1,517	2,067
3	PDCI Costs	12,614	12,766	13,551	15,521
4	Total	25,210	25,286	26,341	28,980
	Actual PDO Costs				
5	PDO Demand Costs	11,217	11,379	11,535	11,654
6	PDO Fuel Costs	1,635	1,373	1,727	2,499
7	PDCI Costs	13,266	13,267	14,235	15,643
8	Total	26,117	26,019	27,497	29,797
	Difference (2)				
9	PDO Demand Costs	(261)	(262)	(261)	(263)
10	PDO Fuel Costs	6	31	(210)	(432)
11	PDCI Costs	(652)	(501)	(685)	(122)
12	Total	(907)	(732)	(1,156)	(816)

Notes:
(1) The 2022 estimate includes actuals up to the end of July 2022.
(2) A positive amount represents a revenue surplus (cost in rates was greater than the actual cost) and a negative amount represents a revenue shortfall (cost in rates was less than the actual cost).

33. PDO demand costs in rates provide recovery of the annual demand costs of the Dawn to Kirkwall and Dawn to Parkway turnback used to facilitate a PDO shift from Parkway to Dawn. As a result of differences in the equivalency of the Dawn to Kirkwall capacity and Dawn to Parkway capacity relative to the rates for each

path[13], there has been an annual revenue shortfall to the Company of approximately $0.26 million each year (Table 1, line 9).

34. PDO fuel costs included in rates provides recovery of the incremental compressor fuel requirements to transport gas on the Dawn Parkway System as customers shift their deliveries from Parkway to Dawn. The PDO fuel cost included in rates is based on the October QRAM Dawn reference price of the prior year. As the Dawn reference price changes quarterly throughout the year, the amount collected in rates is different than the actual costs incurred each year. From 2019 to 2022, the variance in the PDO fuel costs ranges from a revenue surplus of $0.01 million to a revenue shortfall of $0.43 million (Table 1, line 10).

35. PDCI costs included in rates provides recovery of the incremental cost associated with the PDCI payment to customers for their PDO. Due to differences in the PDO forecast underpinning rates and the actual PDO for which the PDCI payment is made, the PDCI amount collected in rates is different than the actual costs incurred each year. From 2019 to 2022, the variance in the PDCI costs ranges from a revenue shortfall of $0.12 million to $0.68 million (Table 1, line 11).

36. Through rates, the Company has recovered the actual PDO costs during the deferred rebasing term with the exception of the differences described above that have resulted in a revenue shortfall to the Company. From 2019 to 2022, the variance in the total PDO costs ranges from a revenue shortfall of $0.73 million to $1.16 million (Table 1, line 12). This shortfall demonstrates that the Company has not over collected for the PDO over the IR term.

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[13] Equivalency differences result when the relationship between Dawn Parkway capacity created by Dawn to Kirkwall turnback is not the same as the relationship between the Rate M12 Dawn to Parkway toll and the Rate M12 Dawn to Kirkwall toll.

4.2. Capacity Used for PDO Shift

37. In Enbridge Gas's MAADs hearing, certain parties claimed that ratepayers were paying twice for the same Dawn Parkway System capacity.[14] This claim is centered on the premise that Union had 210 TJ/d of excess Dawn Parkway System capacity at the time of its 2013 Cost of Service and has recovered the cost of 200 TJ/d[15] of Dawn Parkway System capacity used to facilitate a PDO shift. The Company notes, however, that subsequent to Union's 2013 Cost of Service, Union and parties agreed to reduce the PDO in the manner established in the PDO Settlement Framework,[16] which provided the Company with recovery of the annual demand cost of the capacity used to facilitate the PDO reduction on a revenue neutral basis.[17]

38. At the time of Union's 2013 Cost of Service proceeding, 210 TJ/d of excess Dawn Parkway capacity existed relative to the forecast demands of the Dawn Parkway System. The full cost of the Dawn Parkway System was included in the Company's revenue requirement and allocated based on the forecast demands, consistent with a cost of service treatment. At the time, certain parties submitted that a deferral account should have been established to capture variances related to the long-term transportation revenue forecast, both positive and negative, because it was possible that the excess capacity could be contracted in 2013. In its Decision, the OEB accepted Union's forecast and did not require Union to adjust estimated revenues as was suggested by some parties and rejected the request to establish a

[14] EB-2017-0305/0306, OEB Decision and Order, August 30, 2018, p.49.
[15] 200 TJ/d is the PDO shift that had occurred at the time of the MAADs hearing for customers without M12 service.
[16] EB-2013-0365, Settlement Framework, Appendix B, June 3, 2014.
[17] Ibid.

deferral account. The OEB noted that it believed Union should continue to bear this forecast risk.[18]

39. As part of its 2014 Rates proceeding, parties agreed to the PDO Settlement Framework, which was based on the guiding principle to keep Union whole rather than to enhance or reduce its earnings during the IR term.[19] The context of keeping Union whole in the PDO Settlement Framework was relative to the IR in place at the time and did contemplate revisiting the OEB-approved Dawn Parkway forecast set in Union's 2013 Cost of Service proceeding from the year prior. The PDO Settlement Framework acknowledged this by including the demand revenue for Dawn Parkway System turnback used to facilitate a PDO reduction in rates during the 2014 to 2018 IR term. The PDO Settlement Framework was extended through the 2019 to 2023 deferred rebasing term on the same basis.

40. If the Company adjusts for the excess capacity incorporated in base rates during Union's 2014 to 2018 IR term and/or Enbridge Gas's 2019 to 2023 deferred rebasing term as part of the current Application, the Company will not be kept whole as agreed to by parties in the PDO Settlement Framework and subsequently approved by the OEB. The PDO Settlement Framework will instead reduce the utility's earnings during the IR term(s), as the excess capacity would have otherwise been available to sell. As such, adjusting for the excess capacity as part of this Application is contrary to the guiding principle of the PDO Settlement Framework.

[18] EB-2011-0210, Decision and Order, October 24, 2012, p.22.
[19] EB-2013-0365, Settlement Framework, Appendix B, June 3, 2014, p.1.

4.3. Summary

41. The excess capacity that existed with the 2013 Cost of Service forecast was to the risk and benefit of the Company during its 2014 to 2018 IR term. It is not appropriate at this time to change the intent of the PDO Settlement Framework that was established in 2014 nor to change the OEB-approved cost of service forecast that underpins rates that was approved the year prior in 2013.

42. Enbridge Gas has adhered to the past OEB Decisions and, accordingly, incorporated the excess Dawn Parkway System capacity in base rates in 2013. Enbridge Gas subsequently implemented the PDO Settlement Framework in 2014 during the IR term as agreed to by all parties and accepted by the OEB. Both, the Dawn Parkway System costs and the PDO costs for Dawn Parkway System capacity, have been included in rates consistent with the regulatory mechanisms approved by the OEB at the time, namely the 2013 Cost of Service and the PDO Settlement Framework. As such, Enbridge Gas believes that all aspects of the prior OEB Decisions have been adhered to and no further action is required.

PARKWAY DELIVERY OBLIGATION (PDO) FRAMEWORK

1. The purpose of this evidence is to outline the proposed Parkway Delivery Obligation (PDO) Framework for the continued requirement by the Company for obligated deliveries at Parkway. If approved by the OEB in this Application, this document will replace the Settlement Framework for Reduction of Parkway Delivery Obligation approved by the OEB in Union's 2014 Rates proceeding[1], effective January 1, 2024. The PDO Framework is intended to be used as a reference document for the PDO reduction, Parkway Delivery Commitment Incentive (PDCI) payment and PDO /u reporting. The PDO Framework also incorporates the proposed changes provided at Exhibit 4, Tab 7, Schedule 1.

2. This PDO Framework is organized as follows:
    1. Intent of the PDO Framework
    2. PDO Reduction
    3. PDCI Payment
    4. PDO Reporting

1. Intent of the PDO Framework

3. Bundled and semi-unbundled direct purchase (DP) customers are contractually obligated to deliver gas to Enbridge Gas at various points of receipt upstream or on Enbridge Gas's system, including the interconnect with TransCanada at Parkway and with the Enbridge CDA. For the purposes of the PDO Framework, Parkway and the Enbridge CDA are collectively referred to as Parkway. When Enbridge Gas customers are obligated to deliver gas at Parkway, it is referred to as a PDO.

[1] EB-2013-0365, Decision and Order on Parkway Delivery Obligation, Appendix B.

4. Enbridge Gas continues to rely on the PDO for its system operations. The Dawn Parkway System is physically smaller than it otherwise would be, as gas delivered to Parkway reduces the amount of gas that is required to be transported on the Dawn Parkway System. All customers benefit from the reduced Dawn Parkway System facilities through lower delivery and transportation rates. As such, there is a continued benefit and need for the PDO, which will be facilitated through the parameters set out in this framework.

5. The objective of the PDO Framework is to continue to reduce the PDO through cost effective alternatives when possible while balancing the system operations. The PDO Framework also provides for a payment to customers to recognize the incremental cost incurred by the customer to deliver gas to Parkway and also maintains the guiding principle to keep the utility whole rather than to enhance or reduce earnings.

2. PDO Reduction

6. While the objective of the PDO Framework is to continue to reduce the PDO through cost effective alternatives, the PDO may grow over time should the customer demands on the Dawn Parkway System exceed the Company's continued efforts to reduce the PDO.

7. Enbridge Gas will continue to assess alternatives for reducing the PDO including Dawn Parkway System turnback, infrastructure construction, or market-based alternatives provided the alternative is available, operational, and financially viable. At its sole discretion, Enbridge Gas would consider the use of Dawn Parkway System turnback to reduce the PDO provided that any quantities turned back were

first offered to the market through an existing capacity open season. The priority for utilizing excess Dawn Parkway System capacity is to serve long-term demands.

8. Enbridge Gas will allocate available capacity for reduction of the PDO in the following manner:
   a) DP customers with a PDO less than or equal to a threshold quantity[2] will be provided the opportunity to shift their entire PDO to Dawn;
   b) A proportionate share of any remaining available capacity will be offered to all other DP customers with a PDO who do not hold Rate M12 Dawn to Parkway capacity to meet their PDO; and
   c) Customers with a PDO holding Rate M12 Dawn to Parkway capacity will be offered a similar proportionate share.

9. Customers located in the South and Central service areas[3] will be provided an election form that outlines their current PDO and the quantity available to shift their PDO to Dawn. Customers will be able to choose to shift some or all the quantities made available to them. In addition, customers that do not hold Rate M12 Dawn to Parkway capacity will be allowed to equally participate in any quantities not elected by others.

10. Annually, Enbridge Gas will calculate the costs associated with the PDO reduction. The PDO reduction costs will be calculated using the OEB-approved Rate M12 Dawn to Parkway rate at 100% load factor excluding fuel. Fuel required to transport

[2] The threshold quantity is intended to simplify the administration of DP pools/contracts for those with smaller PDO quantities while still providing a reasonable proportionate share to all other DP customers. When determining the threshold quantity, Enbridge Gas will consider the PDO contracted by customers at that time relative to the capacity available to facilitate a shift in PDO to Dawn.
[3] Union South rate zone and EGD rate zone customers located in Enbridge CDA.

gas to points east of Dawn as a result of new obligated deliveries at Dawn will be included in the PDO reduction cost.[4] Enbridge Gas will capture the PDO reduction costs through the Parkway Delivery Obligation Variance Account (PDOVA), subject to OEB approval in this Application.

3. PDCI Payment

11. Bundled and semi-unbundled DP customers with an obligated point of receipt of Dawn or Parkway will pay the same transportation rate, even though there are incremental costs incurred by a customer obligated at Parkway. To account for the additional costs to the customer of the PDO, Enbridge Gas pays the PDCI on all DCQ quantities obligated at Parkway, as required by the utility. Customers that voluntarily shift their DCQ from Dawn to Parkway or provide non-obligated deliveries at Parkway are not eligible for the PDCI on those delivered quantities.

12. If a bundled DP customer selects a seasonal DCQ and has a Parkway obligation, the customer will only be provided the PDCI on their winter Parkway DCQ quantity through the year. The customer’s higher summer Parkway DCQ is not providing the same peak day benefit as customers that have a Parkway obligation during the winter months from December to March.

13. Annually, the PDCI rate will be set at the OEB-approved Rate M12 Dawn to Parkway rate at 100% load factor including fuel, based on the fuel cost included in

[4] Fuel quantities incremental to the fuel quantities embedded in in-franchise customers rates.

the October QRAM of the prior year, and the facility carbon charge[5]. The PDCI is paid monthly to bundled DP customers based on their obligated DCQ at Parkway.

14. Enbridge Gas will recover the PDCI payment costs from both in-franchise and ex-franchise customers, consistent with the allocation of the Dawn Parkway System transmission demand costs. Any cost variances associated with the PDCI payment costs included in rates and the actual PDCI costs will be recorded in the PDOVA, subject to OEB approval in this Application.

4. PDO Reporting

15. Annual updates on the PDO reduction and PDCI payment costs will be available as part of Enbridge Gas's annual deferral and variance account proceedings. Any cost variances associated with the PDO reduction and PDCI payment costs will be recorded in the PDOVA and disposed of to customers, subject to OEB approval in this Application.

16. The PDO reporting in Enbridge Gas's annual deferral and variance account proceeding will also include the following details regarding:
    a) Capacity that could become available in the following two years that could be used to further reduce the PDO;
    b) Potential market-based solution alternatives to reduce the PDO;
    c) Forecast PDO volumes for the two years following the current year; and
    d) The measures considered and used to reduce the PDO in the current year.

[5] The facility carbon charge was first introduced in the calculation of the PDCI in EB-2018-0205, 2019 Federal Carbon Pricing Program Application.

Comparison of PDO Costs in Rates and Actual PDO Costs

Line No.	Particulars ($000s)	2019 Actual (a)	2020 Actual (b)	2021 Actual (c)	2022 Estimate (d)
	PDO Dawn-Parkway Demand Costs				
1	Dawn to Parkway Demand Costs in Rates	10,956	11,117	11,273	11,391
	Actual PDO Shift Foregone Demand Revenue				
	Turnback Used For PDO Shift (TJ/d)				
2	Dawn to Kirkwall turnback - customers without M12 service	242	242	242	242
3	Dawn to Parkway turnback - customers with M12 service	19	19	19	19
4	Dawn to Parkway turnback - TCE Halton Hills	132	132	132	132
	Rate M12 Demand Rates ($/GJ/mo)				
5	Dawn to Kirkwall	3.058	3.083	3.110	3.130
6	Dawn to Parkway	3.602	3.632	3.665	3.689
	Foregone Demand Revenue from M12 Turnback Used for PDO Shift				
7	Dawn to Kirkwall (line 2 x line 5 x 12)	8,886	8,959	9,037	9,096
8	Dawn to Parkway (line 3 x line 6 x 12)	803	809	817	822
9	Dawn to Parkway Rate T2 BCD Revenue Credit Shortfall	1,528	1,611	1,681	1,736
10	Total Foregone Revenue	11,217	11,379	11,535	11,654
11	PDO Dawn to Parkway Demand Costs Difference (line 1 - line 10)	(261)	(262)	(261)	(263)
	PDO Fuel Costs				
	PDO Fuel Costs in Rates				
12	Incremental PDO Fuel (TJ)	480	480	480	480
13	Prior Year October QRAM Dawn Reference Price ($/GJ)	3	3	3	4
14	Total PDO Fuel Costs in Rates (line 12 x line 13)	1,640	1,404	1,517	2,067
	Actual Fuel Costs				
15	Incremental PDO Fuel (TJ)	480	480	480	480
16	Actual Annual Average Dawn Reference Price ($/GJ)	3	3	4	5
17	Total Actual PDO Fuel Costs (line 15 x line 16)	1,635	1,373	1,727	2,499
18	PDO Fuel Costs Difference (line 14 - line 17)	6	31	(210)	(432)
	PDCI Costs				
	Forecast PDO in Rates (TJ/d)				
19	Direct purchase customers	220	232	240	255
20	Sales service customers	11	11	11	11
21	PDCI Credit ($/GJ/d)	0.150	0.144	0.148	0.160
	Forecast PDCI Cost in Rates				
22	Direct purchase customers (line 19 x line 21 x 365)	12,021	12,188	12,957	14,880
23	Sales service customers (line 20 x line 21 x 365)	593	578	593	641
24	Total PDCI Costs in Rates	12,614	12,766	13,551	15,521
	Actual PDCI Cost				
	Actual PDO (TJ/d)				
25	Direct purchase customers	232	241	253	257
26	Sales service customers	11	11	11	11
27	PDCI Credit ($/GJ/d)	0.150	0.144	0.148	0.160
	Actual PDCI Cost				
28	Direct purchase customers (line 25 x line 27 x 365)	12,673	12,687	13,642	15,002
29	Sales service customers (line 26 x line 27 x 365)	593	580	593	641
30	Total Actual PDCI Cost	13,266	13,267	14,235	15,643
31	PDCI Costs Difference (line 24 - line 30)	(652)	(501)	(685)	(122)