ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

JT5.21 provides the decline in system access spend if Enbridge used a 15-year revenue horizon for calculating CIACs. Please confirm: (a) whether the 15 years of revenue is assumed to also cover incremental O&M costs attributable to the new customers, and (b) whether the numbers also account for infill connections?

Response:

a) Confirmed. The 15 years of revenue also covers incremental O&M costs attributable to the new customers. These costs represent ongoing expenditure to operate and maintain the system and are included in each year of the assumed revenue horizon (i.e., 15 year).

b) Confirmed. The response to JT5.21 includes a forecast of all new customers including infills. The calculations represent the amount of capital investment that can be supported by 15 years of net revenues, generated by the forecast customers be added to the distribution system on a net present value basis.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Please recalculate JT5.21 based on a 10-year revenue horizon.

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

Please see Table 1 containing the requested analysis. Table 1 below presents the analysis conducted at JT5.21 using a 10-year revenue horizon. Item 1) Customer Connections represents the amount of capital investment that can be supported by 10-years of net revenues, generated by the customers forecast to be added to the distribution system in each respective year. Items 2) to 7) are the forecast costs for that year associated with each respective line item.

Table 1
10 Year Horizon

$ Million	2024	2025	2026	2027	2028	Total	
1) Customer Connections	89.0	87.7	93.5	94.6	95.7	460.4	/u
2) DP Relocations	42.3	44.5	45.1	46.3	58.8	237.1	/u
3) DS - CNG	3.5	1.4	1.1	1.1	1.1	8.2	/u
4) GTH - Hydrogen Blending	9.9	11.4	3.3	-	-	24.6	/u
5) TPS - Growth	7.1	75.4	141.7	224.4	180.0	628.6	/u
6) UTIL - Meters Growth	17.1	17.4	19.1	19.9	12.7	86.3	/u
7) EA Fixed - Growth	38.2	39.2	40.2	41.3	23.2	182.1	/u
8) Community Expansion	11.2	19.6	20.5	21.5	7.3	80.1	/u
9) Total	218.4	296.7	364.5	449.0	378.8	1,707.4	/u

Note: Table 1 also assumes indirect O&M overheads are re-allocated across projects as a result of the decrease in customer connections capital spend. Please see Exhibit I.ADR.6 for an updated view of the original System Access table which has been revised to include the TPS-Growth Asset Program. System Access spend decreases by approximately $773 million over the 2024 to 2028 period. /u

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

For infill connections, how much connection capital (e.g. for the service line and meter) could be supported based on forecast revenue for a single residential customer (on an NPV basis – i.e. meeting a PI of 1) over (a) 10 years and (b) 15 years?

Response:

The capital amount that can be supported by the distribution revenue of a residential customer is as follows.

a) Based on a 10-year revenue horizon - $2,713
b) Based on a 15-year revenue horizon - $3,658

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Please calculate the difference in system access spending for each year from 2024-2028 if Enbridge capped the portion of infill connection costs covered by rates at (a) 10 years and (b) 15 years (i.e. the numbers determined in Exhibit I.ADR.3).

Response:

In each of the scenarios below, Customer Connections represents the amount of capital investment that can be supported by 10 or 15 years of net revenues, generated by the customer forecast to be added to the distribution system in each respective year. The revenue cap is applied in a consistent manner regardless of the customer type (e.g. infill, sub-division, commercial, etc.).

The differences below are calculated in comparison to the total 2024 to 2028 System Access spend shown in Attachment 1 of the response at Exhibit I.2.6-SEC-112 of approximately $2.5 billion. Please see Exhibit I.ADR.6 for the revised base case comparison table. /u

a) Under the 10-year cap scenario[1], System Access spend decreases by approximately $773 million over the 2024 to 2028 period. /u

b) Under the 15-year cap scenario[2], System Access spend decreases by approximately $485 million over the 2024 to 2028 period. /u

[1] As presented in the response at Exhibit I.ADR.2.
[2] As presented in the response at JT5.21.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

JT3.11 provided the average cost to connect a home to the gas system as a weighted average of new construction and existing homes. Please provide a breakdown showing the average cost for a new construction home and an existing home, and how long it would take to pay off each. Please provide Enbridge-wide averages in addition to the EGD and UG rate zone figures.

Response:

The requested analysis cannot be provided. For the EGD rate zone, the average cost to connect a residential customer (i.e. a blended cost of new and existing homes) is $4,238 as provided in Enbridge Gas's response to Exhibit JT3.11. For the Union rate zones, granular information on the average cost breakdown for a residential customer is not available as this information is not separately collected by sector, or for new construction homes and existing homes.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Could you please provide a copy of table 1 from page 2 of Exhibit JT5.21 without a change in the connection horizon (i.e. the original numbers)? We are in part trying to determine if the scope/amount for customer connections in row one corresponds with the scope/amount for customers connections in Exhibit 2, Tab 5, Schedule 2

Response:

The following response has been updated to reflect the Capital Update provided at Exhibit 2, Tab 5, Schedule 4, filed on June 16, 2023. /u

The original System Access numbers are provided at Exhibit I.2.6-SEC-112 Attachment 1, updated July 6, 2023. Please see the table below for the System Access portion of the table with a sub-total line for Customer Connections to demonstrate that the amount corresponds to line 2 of Exhibit 2, Tab 5, Schedule 2, Table 1, updated July 6, 2023. Note that the total System Access spend from 2024 to 2028 is updated from $1.8 billion to $2.5 billion due to the reclassification of the TPS-Growth Asset Program.

/u

Table 1 - System Access Forecast 2024 to 2028

USP Category ($ millions)	Asset Program (EGI)	2024 F	2025 F	2026 F	2027 F	2028F
System Access	CC - Commercial/Bulk-Metered - Conversion	1.9	3.3	3.5	3.6	3.6
	CC - Commercial/Bulk-Metered - New	61.0	26.2	27.4	27.8	28.2
	CC - Industrial - New	-	4.3	4.5	4.4	4.5
	CC - Multi-Family/Apartment - New	-	4.0	4.2	4.3	4.3
	CC - Residential - Conversion	27.8	44.4	46.6	47.3	48.0
	CC - Residential - New	210.8	163.8	169.0	164.1	158.9
	CC - Sales Station - Conversion	0.6	0.6	0.6	0.6	0.6
	CC - Sales Station - New	1.8	1.8	1.8	1.9	1.9
Subtotal Customer Connections		304.1	248.1	256.9	254.0	250.1
	CS - Growth	-	-	-	-	-
	DP - Relocations	40.9	43.4	43.5	44.7	56.4
	DS - CNG	3.4	1.4	1.0	1.0	1.1
	GTH - Hydrogen Blending	9.5	11.1	3.2	-	-
	TPS - Growth	6.9	73.6	136.9	216.8	125.5
	UTIL - Meters (growth)	16.5	17	18.5	19.2	12.2
	EA Fixed O/H - Gth	38.2	39.2	40.2	41.3	23.2
	Community Expansion	11.2	19.6	20.5	21.5	7.3
System Access Total		430.6	453.7	521.6	598.6	475.9

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

In the table at Exhibit 2, Tab 5, Schedule 2, does community expansion (line 12) include the individual connections in community expansion areas, or are those included in line 2 (customer connections)? If the latter, please provide a breakout of the customer connections costs in line 2 between subcategories (community expansion, etc.).

Response:

Customer additions related to Community Expansion projects are included in line 12 (Community Expansion) of Table 1 in Exhibit 2, Tab 5, Schedule 2.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

According to JT1.13, the demand forecasts underlying the AMP do not account for the planned 1,500 MW in new gas plants. On or around May 16th, the IESO announced almost 600 megawatts of new gas-fired generation projects in the GTA, the Niagara peninsula, Windsor and St. Clair Township. Will this trigger incremental distribution or transmission reinforcement projects? If yes, please provide details, including what percent of the costs will be covered by the gas plant owners?

Response:

It is EGI's understanding is that the question references the following gas fired generation projects:

	Awarded (MWs)
Uprates	
Atura Power, Portlands	50.0
Atura Power, Halton Hills	31.5
Northland Power, Thorold	23.0
Capital Power, Goreway	40.4
Awarded to 3 Unknown Parties	146.1
	291.0
E-LT1	
Capital Power, East Windsor	100.0
Eastern Power, Greenfield South	195.0
	295.0
Bilateral Negotiation - Uprates	
Atura Power, Brighton Beach	42.5
	42.5
	628.5

With respect to East Windsor and Brighton Beach, the demands for these plants will be served through the proposed Panhandle Regional Expansion Project (PREP). There are no incremental transmission facilities required to serve the forecasted demand beyond what is currently identified in the Asset Management Plan. EGI intends to initiate continuance of the PREP application in June 2023, and details will be provided through the updated LTC application. Costs for any incremental distribution facilities required to serve these power plants would be covered by the power plant owners subject to the terms of EBO 188.

With respect to the remaining power plants listed, EGI cannot comment on whether these facilities will trigger incremental distribution or transmission projects, nor the scope or cost of such projects. Such details will not be available until it is determined how and by whom these plants will be served for their natural gas supply. Following this, incremental transmission facility requirements would be determined through assessment of available capacity, an assessment of Integrated Resource Planning Alternatives, transmission system capacity open seasons, and/or expressions of interests for firm distribution capacity.

The cost recovery for any new transmission facilities required to support these projects would be subject to EBO 134. Incremental distribution facilities would be established through an assessment of future distribution system demands in the subject areas, and a review of Integrated Resource Planning Alternatives. Costs for the incremental distribution facilities required to serve these power plants would be covered by the power plant owners under the terms of EBO 188.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Please reconcile the calculation of aggregate excess determined from throughput (source I.4.2-FRPO-97) provided and the allocations provided in I.7.1-IGUA-76.

a) We are attaching our calculation of resulting aggregate excess allocations by rate class from FRPO-97 (AGG file).
b) We have read and re-read the evidence in Ex. 4/T2/S1 pg. 18-20 and do not understand the relevance of 217.7PJ, how it was determined and the role that "adjustment" had in Table 4 nor the reconciliation requested above. Please clarify those aspects of 217.7 PJ.

Response:

The volumes used to calculate aggregate excess in the attachment provided by FRPO (13,147,613 10^3m^3) reflect sales service demands[1] and results in a total storage requirement of approximately 171.6 PJ, but this does not reflect storage requirements calculated for direct purchase (DP) customer demands. Both sales service and DP customer demands are included in the calculation of aggregate excess.

As reflected in Table 1 below, including DP customer demands in the aggregate excess calculation along with T-service storage requirements which are determined based on the storage space methodologies approved in the T-service rate schedules, results in a total storage requirement of 217.7 PJ.

Table 1
Calculation of 2024/25 Storage Requirement

Line No.	Particulars (PJ)	Annual Demand[2]	Winter Demand	Storage Space Allocation
		(a)	(b)	(c)
1	System	514.9	372.7	159.7
2	DP	244.5	144.2	43.0
3	T-service			15.0
4	Total storage in rates			217.7

[1] Sales service demand of 13,147,613 10^3m^3 is also provided in response to Exhibit I.4.2.FRPO.97 (line 22), and Exhibit 3, Tab 3, Schedule 1, Attachment 8, p.15 (line 54)

[2] Aggregate excess was calculated on the basis of the storage contact year for rebasing. Therefore, total demand for the April 2024 to March 2025 period was used to calculate the storage requirement of 217.7 PJ.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

EGI is requesting 4.8 PJ of empty storage for November 1st and 10.8 PJ of full storage space for March 31st. We would recommend that EGI that with Dawn deliveries, EGI fill the 4.8PJ in December to provide almost half of the March 31st request. Is EGI's only concern the risk of December pricing? Please elaborate & present any quantitative analysis that supports that concern?

Response:

Enbridge Gas's proposal to meet operational contingency requirements is outlined at Exhibit 4, Tab 2, Schedule 4 (page 1):

> "15.6 PJ of operational contingency will be required to support the reliability and resilience of the Enbridge Gas storage, transmission, and distribution systems."

The requirement to maintain 4.8 PJ of empty storage space on November 1st is for operational contingency purposes and is not based on economic considerations such as monthly commodity prices. In other words, that space is required to remain empty and cannot be used to inject gas supply. During the Technical Conference, Mr. Pardy articulated the need for operational contingency:

> "Operational contingency is really there for the benefit of the system operator to help manage and, like you say, provide services that the company provides and to assist in the reliability and resilience of the storage system."[1]

From an operational perspective within the winter months, Enbridge Gas makes its procurement decisions based on weather, customer demands, its supply position, and economic conditions at that time. Should those conditions allow for incremental gas to be purchased in December, Enbridge Gas does so on an actual basis.

---

[1] Technical Conference Vol 7 Tr 19, lines 14-18.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

We are attaching an Excel spreadsheet (Cost file) that calculates the summer winter spread at Dawn in previous periods. Please confirm or correct our determination.

a) In that same spreadsheet, we include the forecasted Dawn purchases used to generate the load balancing cost to bundled customers from evidence. In the last tab, we evaluate the cost to move some forecasted June Dawn purchases to the months of Dec. to Feb. Please confirm or correct our assessment.

Response:

Enbridge Gas cannot verify the foreign exchange rates used in FRPO's analysis as they do not match the exchange rates used by the Company which are obtained from the Bank of Canada and no source was provided. Enbridge Gas attempted to validate the rates used in FRPO's analysis against both the actual exchange rates for that day, as well as the average for that month.

There are differences in the "Price Variance – Load balancing ($000s)" line of the "GAS PURCH" tab that do not match Exhibit 4, Tab 2, Schedule 1, Attachment 1.

The table used from Exhibit 4, Tab 2, Schedule 1, Attachment 1 only reflects the storage that has been included in proposed rates and does not include the 10 PJ of incremental market-based storage over aggregate excess. The request to purchase 10 PJ of market-based storage above aggregate excess (which is 2 PJ above current storage levels in the current Gas Supply Plan) is also a Phase 2 issue.

The analysis provided does not reflect how a change in winter procurement strategy would be implemented in the Gas Supply Plan. Moving 10 PJ of supply purchases from a single month and evenly spreading them over the winter months would have broader impacts on the Gas Supply Plan that are not recognized in the analysis.

Other than the points above, the mechanics of the spreadsheet seem correct.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

How many pipeline contractors does EGI have in each of the:

a) Distribution services.
b) HP or large diameter projects

Response:

Enbridge Gas has several pipeline contractors that provide constructions services. The work is not specifically divided into the categories above.

For the majority of pipeline construction work, EGI uses two primary pipeline contractors that will complete main, services, replacement, and integrity repair work on distribution and transmission pipelines. This includes HP and large diameter projects. These two primary contractors are part of the Alliance Partner contract.

For some large projects and storage/transmission facilities, other contractors may be used.

Enbridge Gas also uses an additional eight contractors to complete main and service construction work in subdivisions where joint utility trench installations are required.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

JT5.45 provides some qualitative information on the benefits of the Alliance partnership for ratepayers, but the only quantitative metric is 1% performance improvement. Given the statement that "Over the 20-year history this has enabled Enbridge Gas to attain resourcing efficiencies", please provide any internal or external audits or evaluations of the system that demonstrate this statement or drove ongoing improvement.

a) If no evaluations have been done, please provide a summary of quantitative metrics that establish the company's statement.

Response:

Enbridge Gas has not conducted internal or external audits or evaluations focused on efficiencies with the Alliance Partner Contract.

The response to Exhibit JT5.45 outlined several quantitative factors that drive effective spend within the contract.

Resourcing efficiencies have occurred over a 20-year time period and have not been explicitly tracked. Examples include:

- Integrated work management systems that support Business to Business (B2B) transactions have resulted in resourcing efficiencies in the areas of work order generation and invoice processing. Sustained cost savings are estimated at $2.5 million annually.
- Quality Management systems and project level quality audits have resulted in resourcing efficiencies in the areas of pipeline and quality inspections. Sustained cost savings are estimated at $4 million annually.
- The portfolio approach of the Alliance Partnership has resulted in avoided costs that would have been required to support an RFP for each individual project. Enbridge Gas completes approximately 1000 capital projects on an annual basis. These avoided costs are more challenging to quantify. In order to RFP individual projects, FTEs would need to increase in Supply Chain, Drafting and Project Management.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

SEC-179 identifies growths in FTE

a) For the distribution operations (282) and Engineering, Storage and Transmission (150), what are current FTE levels?
b) What initiatives, changes or increases are driving these staff increases when very recently EGI reduced staff?

Response:

a) 2022 actual FTEs are shown in Exhibit I.4.4-CCC-87 Attachment 1 Table 1:
   - 1,689 for Distribution Operations
   - 736 for Engineering & STO

b) Exhibit 4, Tab 4, Schedule 3 paragraphs 10 and 11 describe the drivers for FTE increases for these departments. As discussed in Exhibit I.4.4.-STAFF-138 and Exhibit JT7.10, the reductions in FTEs through the organizational restructuring and VWO were largely in management level positions that would not have had the appropriate skillset for the nature and type of the increased workload the Company is facing today.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Footnote 12 explains source of volume data but excludes LUF of EGD from 2019. What is the reason for that omission and was it estimated for the purposes of display?

a) Supplemental to 20230524 SEC Question 2, please confirm that the 2024 UFG for the purposes of rate setting would include all of the volumes from the three categories identified in Footnote 12 for the years 2020 to 2022 (update with 2022 final results) multiplied by the most recent QRAM cost of gas at the time of 2024 Draft Rate order. If not, please clarify.
b) How is EGI determining leak volumes as distinct from other UFG? (ED-133 Attach 3)

Response:

2019 LUF Data for EGD was omitted due to the lack of comparable storage UFG data for 2019. The LUF volumes reported in Exhibit 4, Tab 3, Schedule 1 Table 3 for 2019 are based on the average of historical LUF volumes from 2020 and 2021.

a) Not confirmed. The 2024 UFG volume forecast for the purposes of rate setting will include all of the volumes from the three categories identified in footnote 12 for the years 2019 to 2021 multiplied by the approved reference price at the time of the 2024 draft rate order. Enbridge Gas is not proposing to update the volumes underpinning the 2024 UFG volume forecast, as set out in Exhibit 4, Schedule 3, Tab 1.

b) Enbridge Gas reports fugitive emissions, as well as combustion, vented and flared emissions directly resulting from Enbridge Gas's operations to Environment and Climate Change Canada and the Ontario Ministry of the Environment, Conservation and Parks on an annual basis. The leak volumes reported in Exhibit I.4.3-ED-133 Attachment 3 are based on volumes calculated for the annual reporting.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

JT5.44 requested criteria or factors to move projects from Copperleaf to GDS and used St. Laurent as an example. The answer provided does not help us with the criteria or factors (beyond tacit knowledge). Please provide some form of criteria, decision-matrix or process flowchart to help us understand.

Response:

We understand that what is described as “GDS” in the question refers to the Enbridge Gas Distribution and Storage Risk Management process as outlined in Section 4.2 on pages 50-53 of Exhibit 2, Tab 6, Schedule 2, the 2023-32 Asset Management Plan. Figure 4.2-3 in this section provides a graphical representation of EGI’s risk evaluation framework, for which 3 regions are assigned, and forms the basis for how decisions are made regarding requirements for risk treatment plans.

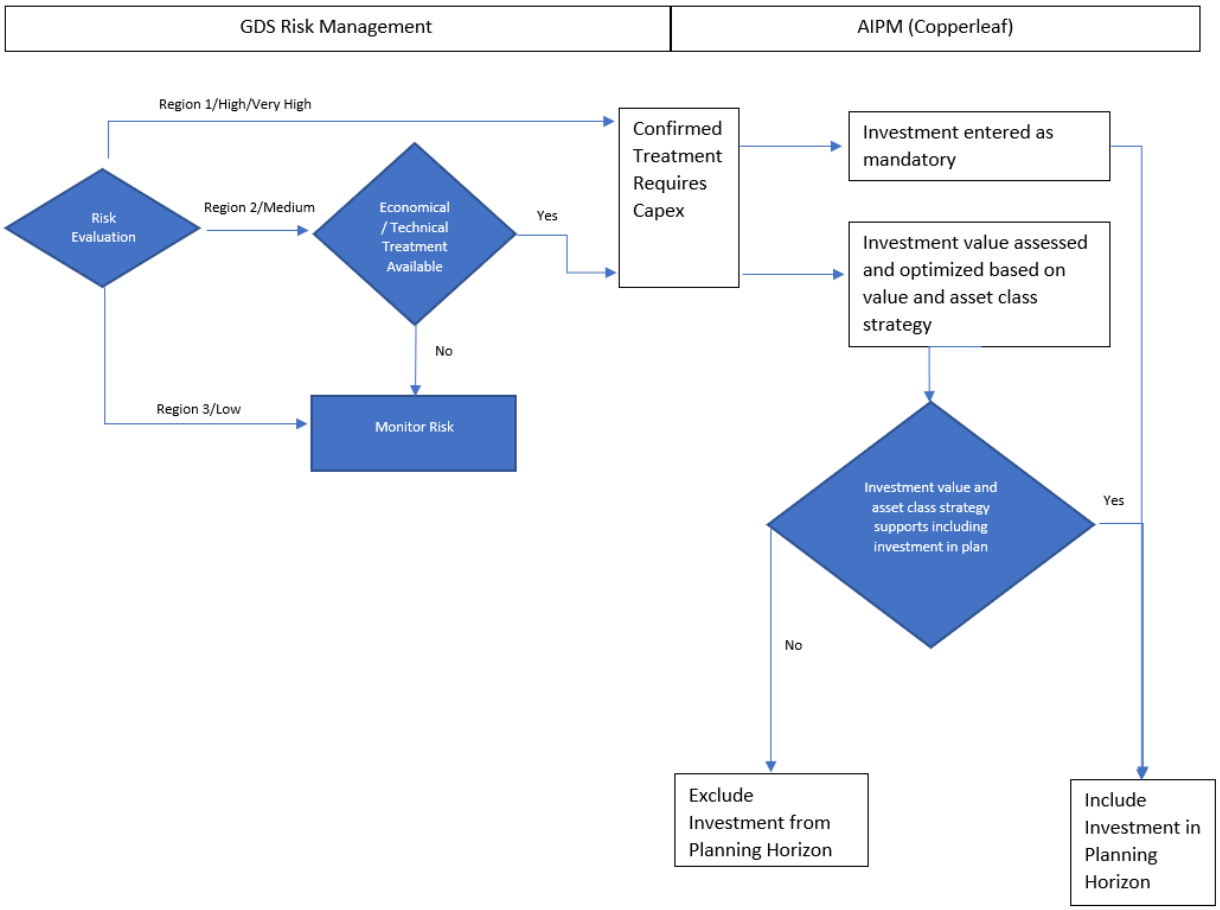
Risks that are evaluated as Region 1 risks, which would generally be those risks categorized as high or very high in Enbridge Gas’s 7x7 Risk Matrix (see Exhibit I.2.6-SEC-121) require treatment plans under GDS’s risk management standards. Where the treatment plans involve capital investment, that investment becomes mandatory as described in Table 4.1-2: Investment Categories, on page 46 of the AMP. As mandatory investments, these investments become time constrained and are not optimized among other value driven investments based on their value, but are assigned the required capital in the specified years within the capital planning horizon.

Risks that are evaluated as Region 2 risks, which would generally be those risks categorized as medium in Enbridge Gas’s 7x7 Risk Matrix, must be treated, unless they are already managed as low as technically and economically feasible. Technical feasibility is assessed based on the availability of technically viable solutions to further reduce the risk. For treatment plans which require capital investment, economic feasibility is evaluated using Copperleaf value framework, as described in detail in Exhibit I.2.6-CCC-49, while taking into consideration asset class strategies and available capital. Capital investments required to support treatment plans are subject to optimization and review among other value driven investments as described on pages 55 and 56 of the AMP prior to inclusion in the capital planning horizon.

Risks which are evaluated as Region 3 risks, which would generally be those risks categorized as low in Enbridge Gas’s 7x7 Risk Matrix, are monitored according to applicable procedures and related business processes and requirements, and would not drive any capital investment.

Figure 1 below depicts how the GDS Risk Management and Asset Investment Planning and Management (Copperleaf) processes are related.

Figure 1: GDS Risk Management/AIPM Interface



In summary, the determination that a risk is in Region 1, or is high to very high on the 7x7 Risk Matrix, is the basis for determining if a risk requires treatment under GDS's risk management standard. If the risk treatment requires capital investment, that investment is considered mandatory and is time constrained and is not optimized based on value during the Copperleaf optimization.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

JT5.45 Sought a better understanding of the value of the Alliance Partnership. The Answer does not provide data, metric, benchmarks or any substantive evaluation that the company has done to determine the value of single sourcing projects whose labour components can be tens of millions of dollars.

a) Can the company provide any form review, study or even evaluations that have been done?
b) For EGI's top three contractors, what is the average annual payment (we are asking top three to try to limit the specificity to any contractor).

Response:

a) See Attachment 1 for a copy of the report entitled "Gas Distribution Contracting Benchmark & Best Practices", which was prepared by PowerAdvocate (now part of Wood Mackenzie) in 2021. Enbridge Gas had commissioned the report at the time as an independent review of its Alliance Partner contracts and associated spend and to identify applicable industry best practices and recommendations for potential improvements.

   Enbridge Gas notes that the PowerAdvocate report is comprised in large part of information that is of a highly commercially sensitive or proprietary nature which, if disclosed publicly or to any party that could gain an undue competitive advantage from the information, is likely to prejudice the competitive position of the Company, the Alliance Partners, and/or Wood Mackenzie. For this reason, Enbridge Gas is providing a confidential unredacted copy of the report, with confidential information identified by highlights, to parties that have filed a signed Confidentiality Declaration and Undertaking in this proceeding. A caveat is that the City of Kitchener is provided the redacted version notwithstanding its previous filing of a signed Declaration and Undertaking, because in Enbridge Gas's understanding the City of Kitchener has contracted with the same Alliance Partners for construction services and could therefore use the confidential information found in the report (including detailed pricing structure and unit rates) to its advantage in future procurement negotiations with construction contractors.

b) The table below provides the average annual payment to Enbridge Gas's top three pipeline contractors. The average payments were calculated over the period 2020 to 2022 and the top three contractors were determined by selecting the contractors with the highest average payments over the aforementioned timeframe.

Contractor #	Average Annual Payment (millions)
Contractor 1	$288
Contractor 2	$267
Contractor 3	$22

Gas Distribution Contracting Benchmarks & Best Practices

Enbridge

Final Report

June 15, 2021

Power Advocate

Overview of Scope of Work

3-week engagement to review up to 4 Enbridge Alliance contracts and associated spend, and provide market insights and best practices based on PowerAdvocate's Energy FactBase™

- **Contracting Benchmarks & Best Practices**: Review and analyze Enbridge's position in 4 representative alliance contracts and compare against market best practices. Provide presentation-style deliverables illustrating and/or quantifying Enbridge strengths, weaknesses, and opportunities for improvement. Provide Alliance Contracting insights in specific areas.
  - Benchmarks
    - Utilization of unit rates/T&M/lump sum
    - # of units within contracts
    - % services, material and equipment
  - Best Practices
    - Sole-source vs. competitive bidding
    - Performance Management/KPI's
    - Shared risk and productivity incentives
    - Performance tracking and work allocation
    - Union Labor cost management
    - Construction services group with a business relationship to the utility
- **Regulatory Factors:** Summarize different regulation approaches observed within the PowerAdvocate FactBase™ (mostly North American gas and electric utilities); conduct data review on the prevalence of each regulation type
- **Escalation Analysis:** Review Enbridge existing contract language regarding rate escalation; Provide industry best practices & recommended option; Should-cost analysis for past 3-5 years (EGD pricing vs. market); etc.

[redacted]

Power Advocate

[redacted]

[redacted]

[redacted]	[redacted]	PowerAdvocate Recommendation
[redacted] [redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]

Agreement Terms Analysis - Summary

Influential Term	Legacy Enbridge – AECON	Legacy Enbridge – NPL	Legacy Union – AECON / NPL	[redacted]
Contract Term	✓ 2014-19, extended through 2021	✓ 2014-21	✓ 2017-19, extended through 2021	• [redacted]
Warranty Period	✓+ 12 years	✓+ 12 years	✓– No period specified; defects covered only 1 year from Acceptance of Work	• [redacted]
Commercial General Liability (CGL) Insurance Requirements	✓– $10M Coverage though no language re: coverage by occurrence / aggregate	✓– $10M Coverage though no language re: coverage by occurrence / aggregate	✓ $10M Coverage with a limit of $10M by occurrence, No language re: coverage for aggregate	• [redacted]
Indemnity	✓	✓	✓	• [redacted]
Termination	✓ 30 Days notice	✓ 30 Days notice	✓+ At any time	• [redacted]
Payment Terms	✓ Net 30	✓ Net 30	✓ Net 30	• [redacted]

✓+ Best of Breed term, meeting 'best practices' target

✓ Term is acceptable relative to best practices targets

✓– Term may present an opportunity for improvement

PowerAdvocate

Agreement Terms Analysis – Summary (Cont'd)

Influential Term	Legacy Enbridge – AECON	Legacy Enbridge – NPL	Legacy Union – AECON / NPL	[redacted]
Continuous Improvement / Performance Incentive *See Target Price / Alliance Analysis for additional insights*	✓ • Agreement incorporates KPIs via Scorecards • No formal performance incentives	✓ • Agreement incorporates KPIs via Scorecard though incentives are limited, e.g. OH performance	✓+ • Agreement incorporates KPI incentives via Scorecard and distinct Performance based incentives	[redacted]
Pricing Alliance Structure *See Target Price / Alliance Analysis for additional insights*	✓ • Target pricing mechanism with limited means to cap / credit margins earned	✓ • Limited incentives vis a vis Overhead adjustment per scorecard performance	✓ • Target pricing mechanism with caps based on EBT reconciliation	[redacted]
Price Escalation *See Target Price / Alliance Analysis for additional insights*	✓ • Escalation inflation factor applied to all. • No distinction between rates, units, equipment. • Over the past 5 years, this factor has tracked beneath traditional index based adjustments	✓ • Fixed annual Escalation applied to all - not tied to indices. • No distinction between rates, units, equipment. • Over the past 5 years, this method has tracked beneath traditional index based adjustments	✓ • Index based escalation by labour and equipment -- which have largely tracked above inflation and LEGD factors utilized	[redacted]

✓+ Best of Breed term, meeting 'best practices' target
✓ Term is acceptable relative to best practices targets
✓– Term may present an opportunity for improvement

Agreement Terms – Summarized

Legacy Enbridge / Union Gas Contract Terms - ALL

Influential Terms	Legacy Enbridge – AECON *AECON Agreement 2015 Final*	Legacy Enbridge – NPL Canada *Link-Line 2015 EA Agreement Final*	Legacy Union Gas – AECON *Sch. 1 Facilities, Sch. 3 Special Reqmt's*	Legacy Union Gas – NPL Canada *Sch. 1 Facilities, Sch. 3 Special Reqmt's*
Contract Duration	• Dec. 2014 – Dec. 2019 • Renewal notice required in writing by May 29, 2018 • No specified length to renewal extension • Has been extended to 2021	• Dec. 2014 – Dec. 2021 • Renewal notice required in writing by May 29, 2020 • No specified length to renewal extension	• Jan. 2017 – Dec. 2019 • No specified length to renewal extension • Has been extended to 2021	
Warranty Period	• 12 years • E.g. Longest minimum survey frequency (10 years) plus two years • No acceptance of work language included	• 7 years for Mains • 12 years for services and any other parts of the plant • E.g. Longest minimum survey frequency (5/10 yrs) plus two years	• Upon completion of the Work contracted hereunder, including any Addenda, in a manner fully satisfactory to the Engineer and in accordance with the Contract, the Engineer will notify the Contractor in writing of his final acceptance of the Work on behalf of the Company • The Contractor also guarantees to repair or replace, at its own expense, any part of the Work that may develop any defects • Such defects become known to the Company within a period of <u>one year</u> after final acceptance of the Work by the Engineer.	
Commercial General Liability (CGL) Insurance Requirements	• Comprehensive General Liability insurance having a minimum inclusive coverage limit including personal injury and property damage of at least $10,000,000 • No value by occurrence or aggregate sum	• Comprehensive General Liability insurance having a minimum inclusive coverage limit including personal injury and property damage of at least $10,000,000 • No value by occurrence or aggregate sum	• Commercial General Liability Insurance having a limit of at least $10,000,000 (ten million dollars) per occurrence for bodily injury and property damage	
Indemnity	• The Contractor shall, and hereby agrees to, indemnify EGD, its Affiliates and the directors and officers and agents and employees thereof against and save and hold them harmless from any and all liabilities, claims, demands, losses, damages, costs and expenses		• …the Contractor shall indemnify and save harmless the Company and the Engineer from and against all demands, claims, proceedings, or liability imposed by law or assumed by legal settlement whensoever arising, whether before, during or after completion of the Work	
Termination	• This Agreement may be terminated immediately by EGD upon written notice for select instances (force majeure event, material breach, etc.) • Agreement may also be terminated by EGD upon thirty (30) days' written notice to the Contractor such notice specifying the basis for such termination in select circumstances -- includes 30 day cure period		• the Company may, with or without cause, at its sole option, terminate the Work or any part thereof, at any time, by giving notice in accordance with paragraph 97) herein, even if the Contractor has not defaulted on any of its obligations or responsibilities pursuant to this Contract • The Company may, with or without cause, terminate the work any time by giving notice in person or through mail	
Payment Terms	• Net 30 days of receipt of invoice		• The Compensation to be paid shall be pursuant to Schedule III – Special Instructions and Schedule IV – Price Schedules. TBD	

Power Advocate

Agreement Terms – Summarized (Cont'd)

Legacy Enbridge / Union Gas Contract Terms - ALL

Influential Terms	Legacy Enbridge – AECON	Legacy Enbridge – NPL Canada	Legacy Union Gas – AECON	Legacy Union Gas – NPL Canada
Continuous Improvement	• Per agreement, "…a joint assessment of the project will be completed to ensure that knowledge learned from the project is documented and applied to future projects"		• To continue to build on the success of the existing relationship and contract, both Union Gas and the Contractor will commit to reviewing proposed contract and/or process improvements at each Alliance Working Team meeting. • The Alliance partnership is committed to delivering on yearly productivity savings. The productivity goal will be set at 1% of the total yearly spend. Specific productivity savings and losses will be tracked through the year and approved by the appropriate C&G/ECS Manager	
Pricing Alliance Structures	• Target EBT profit of 8% • Incentive based adjusted targeted earnings calculated at fiscal year end based on Alliance Scorecard and agreed to formula	• N/A	• [redacted] • Above EBT target profit, contractor pays back a % • Productivity savings of [redacted] above that and Company/contractor will split savings	
Price Escalation	• On an annual basis (first day of fiscal year), unit pricing, fixed OH, labour, equipment, and appurtenance rates adjusted via an inflation factor (multiplier) • [redacted]	• Unit Pricing, Labour, Equipment and Appurtenance rates will be upwardly adjusted on an annual basis commencing in the second year of the Agreement Term by a rate of [redacted]	• Labour rates: Per negotiated collective agreement and escalated per weighted Canadian Labour / Equipment indices • Equipment rates: by CPI indices [Equipment CANSIM table 327-0055 (5 year avg.), Vehicles CANSIM table 326-0020 (5 year avg.), Vehicle Operating Expenses CANSIM table 326-0020 (yearly amount)] • Unit Prices: Per weighted Canadian indices [redacted]	

Power Advocate

Target Price Analysis by Agreement

Metric Evaluated	Legacy Enbridge - AECON	Legacy Enbridge – NPL Canada	Legacy Union – AECON / NPL Canada	[redacted]
Profit Margin %	✓ [redacted] *See Slides 19 - 22*	✓– N/A - Not provided as part of agreement	✓+ [redacted]	[redacted]
Earnings Band	✓ **Margin above / below Target[1]:** [redacted]	✓– N/A - Not provided as part of agreement	✓ **Margin above Target:** [redacted] **Margin below Target:** [redacted]	[redacted]
Audit / Reconciliation Process (EBT, Other / Misc.)?	✓ At the discretion of EGD Manager; self reported by AECON	✓– For Overhead ONLY	✓+ Yes, annually via 3rd party (Spectra Audit Services)	[redacted]

✓+ Best of Breed term, meeting 'best practices' target
✓ Term is acceptable relative to best practices targets
✓– Term may present an opportunity for improvement

1 – % based on agreed to adjusted earnings before tax formula

Power Advocate

Target Price Analysis by Agreement (Cont'd)

Metric Evaluated	Legacy Enbridge - AECON	Legacy Enbridge – NPL Canada	Legacy Union – AECON / NPL Canada	[redacted]
Compensation to Supplier to 'True Up' Margin?	✓ Yes, credit / payment incentive applied to Margin (per Scorecard process).during reconciliation	✓ For Overhead ONLY	✓+ Yes; credit / payment incentive applied to actual margin earned during reconciliation	[redacted]
Additional Margin % Beyond Target?	✓ Yes; Scorecard	✓– N/A	✓ Yes; Scorecard, Performance Incentives	[redacted]
Max Compensation	✓– [redacted] *See Slide 19, 20*	✓– N/A	✓ • [redacted]	[redacted]
Net Credits	✓– • Limited means to band upside margin earned on EBT • Net credit applicable only in instances where Supplier failed to meet scorecard target • See Slide 19, 20	✓– N/A	✓+ EBT [redacted] Scorecard • [redacted] Productivity: [redacted]	[redacted]

Power Advocate

Target Price Analysis by Agreement (Cont'd)

Metric Evaluated	Legacy Enbridge - AECON	Legacy Enbridge – NPL Canada	Legacy Union – AECON / NPL Canada	[redacted]
Scorecard Incentive?	✓ Yes, final scorecard value applied to reconciled EBT margin through agreed to formula	✓ [redacted]	✓+ [redacted]	[redacted]
Productivity Incentive?	✓– Language exists within agreement, nothing quantifiable / formal found however	✓ • OH adjustment acts as a performance incentive • No other incentives found	✓ [redacted]	[redacted]

✓+ Best of Breed term, meeting 'best practices' target
✓ Term is acceptable relative to best practices targets
✓– Term may present an opportunity for improvement

Price Escalation by Type per Agreement

Metric Evaluated	Legacy Enbridge - AECON	Legacy Enbridge – NPL Canada	Legacy Union - AECON	Legacy Union - NPL	[redacted]
Labour / Rates	✓ • [redacted]	✓ • [redacted]	• Negotiated per Bi-Annual Labour Agreement		[redacted]
Equipment			✓ [redacted]	✓ [redacted]	[redacted]
Unit Rates			✓ • [redacted]	✓ [redacted]	[redacted]
Overhead (OH)	✓– • Fixed OH agreed upon amount paid in 12 equal installments • [redacted]	✓+ • Fixed OH paid via 12 installments as fixed cost, • [redacted]	✓ • Fixed OH paid via 12 installments as a fixed cost. • Annual Increases (fixed and variable) agreed and approved during reconciliation process		[redacted]

✓+ Best of Breed term, meeting 'best practices' target
✓ Term is acceptable relative to best practices targets
✓– Term may present an opportunity for improvement

Current Equipment Escalation vs. Alternative

The equipment indices defined within the respective agreements increased by [redacted] *from Jan '16 to Jan '21. The LEGD (fixed) inflation factors fared considerably better than the LUG index-based factors over the period evaluated.* [redacted]

[redacted]

Supplier	Equipment Index / Weight %	Vehicle Purchase / Weight %	Vehicle Operating / Weight %
LEGD AECON	Per Inflation Factor, [redacted]		
LEGD NPL	[redacted]		
LUG AECON	CANSIM Table 18-10-0058-02 Machinery and Equipment Price Indexes, CONSTRUCTION [redacted]	CANSIM Table 18-10-0004-07, Consumer Price Index, Purchase and Leasing of Passenger Vehicles [redacted]	CANSIM Table 18-10-0004-07, Consumer Price Index, Purchase and Leasing of Passenger Vehicles [redacted]
LUG NPL	CANSIM Table 327-0055 Machinery and Equipment Price Indexes, CONSTRUCTION [redacted]	CANSIM Table 326-0020, Consumer Price Index, Purchase and Leasing of Passenger Vehicles [redacted]	CANSIM Table 326-0020, Consumer Price Index, Operation of Passenger Vehicles [redacted]
Alternative (NEW)	*IPPI: Machinery and Equipment, Canada* ***(NEW)*** [redacted]	*IPPI: Motor Vehicle Manufacturing, Canada* ***(NEW)*** [redacted]	CANSIM Table 326-0020, Consumer Price Index, Operation of Passenger Vehicles [redacted]

[redacted]

Current Unit Price Escalation vs. Alternative

The [redacted] fixed escalation tracked lower than other index-based methods. [redacted]

Supplier	Labor Weighting / Escalation	Equipment Weighting / Escalation
LEGD AECON	Per Inflation factor, [redacted]	
LEGD NPL	[redacted]	
LUG AECON	[redacted]	[redacted]
LUG NPL	[redacted]	[redacted]
Alternative (NEW)	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Power Advocate

Overhead Mark-up Analysis

Consider additional contractual mechanisms / incentives to better band Overhead costs:

Overhead Analysis	LEGD – NPL	LEGD – AECON	LUG – NPL	LUG - AECON
Y-o-Y Change as a % of Cost	• Assume [redacted] reduction (per agreement), require data to confirm	• Largely consistent year over year	• Continue to fall despite increasing revenues	• Volatile spikes despite flat revenues
Fixed OH	[redacted]	• Agreed upon amount paid in 12 equal installments, escalated annually per inflation factor [redacted]	• Agreed upon amount paid in 12 equal installments, OH reviewed and approved as part of reconciliation	
Variable OH	• Invoiced per Target Price estimate for discrete work package(s)	• Invoiced monthly and applied as an allocated cost line item via annual EBT	• Agreed upon % applied to each invoice. Reviewed and approved as part of the Annual Reconciliation Process	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]			

[redacted]

1 – Excl. LEGD NPL (No data available)

Power Advocate

Profit Margin + Additional Incentives by Agreement[1]

In instances where LUG (AECON / NPL) EBT margins exceed [redacted], the agreement structure incorporates a net credit to Enbridge (realized '19/20) for the additional amount. The Supplier is still capable of achieving additional margin through Scorecard and Performance incentives:

[redacted]

1 – A

Profit Margin + Additional Incentives by Agreement (Cont'd)

[redacted]

Power Advocate

LEGD AECON – Target Price Breakdown (Cont'd)

Reconciliation Payment is Capped on AEBT <u>**not**</u> EBT

Per the contractual language shown below, the [redacted] cap on margin is applicable only in instances where [redacted] The cap does not extend to the EBT earned during the year. This was the case in 2019, per the illustration shown below:

Reconciliation Contract Language 11.3.d.C:

[redacted]

[redacted]

Difference in language shown in True Up Calc vs. Contract Language
Contract: AEBT = EBT [redacted] S-100%), where EBT = [redacted]
True Up: AEBT = TEBT [redacted] S-100%), where TEBT = [redacted]

AECON – 2019 ONTARIO TRUE UP CALCULATION

2019 Revenue	[redacted]
EBT - Earnings	[redacted]
EBT %	[redacted]
Targeted EBT (TEBT)	[redacted]
2019 Scorecard (S)	[redacted]
AEBT = TEBT + [redacted] *(S-100%)	[redacted]
AEBT - [redacted]	[redacted]
Difference Due to AECON [redacted]	[redacted]
[redacted] x Revenue	[redacted]
True Up Payment to AECON [redacted]	[redacted]

AECON – Year Over Year Scoring / %

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

LEGD AECON – Target Price Breakdown (Cont'd)

Limited means to recoup excess margin earned[1]

The breakeven (dead band) where a credit would be due (to EGD) is only applicable in instances where AECON's annual scorecard is < 80. AECON has averaged ***+30%*** *above the stretch target set between 2017/20:*

EBT Assumptions[2]:
AEBT = EBT +5%(S-100%)*
EGD Credit: EBT > AEBT+1
EGD Payment: EBT < AEBT-1

Scorecard Assumptions:
Above Target: >125
Meets Target: 100 – 125
Below Target: <100

2 – Per Agreement (11.3 Earnings Before Tax Reconciliation)

AECON – Year Over Year Scoring / %

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

1 – If EBT >AEBT+1%, this amount will equal 50% of the Revenue that contributes to the amount of Earnings Before Tax above the Contractor's AEBT + 1%.

Power Advocate

[redacted]

[redacted]

[redacted]

- [redacted]
  - [redacted]
  - [redacted]
- [redacted]
  - [redacted]
- [redacted]
  - [redacted]
  - [redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Power Advocate

[redacted]

[redacted]

[redacted]

- [redacted]
  - [redacted]
  - [redacted]
- [redacted]
  - [redacted]
- [redacted]
  - [redacted]
  - [redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
  - [redacted]
  - [redacted]
- [redacted]
  - [redacted]
- [redacted]
  - [redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
  - [redacted]
- [redacted]

[redacted]

[redacted]

	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted] [redacted] [redacted]

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Power Advocate

[redacted]

[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

- [redacted]

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

Power Advocate

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Power Advocate

[redacted]

[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Power Advocate

[redacted]

[redacted]

[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

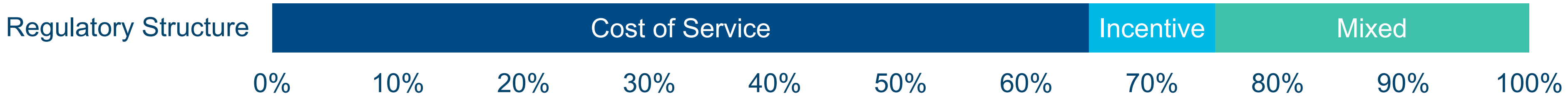
[redacted]	[redacted]
• [redacted] • [redacted] • [redacted]	• [redacted] • [redacted] • [redacted]

[redacted]

[redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]

Regulatory Factors: Cost of Service vs. Incentive

Most N. American utilities adopt a Cost of Service regulatory model though many do incorporate an Incentive / Mixed model as distinguished below. The industry does reflect a growing shift towards a mixed / incentive model -- which is expected to continue.



Cost of Service *(~65%)*

- Regulated by a state / provincial commission
- Commission sets a rate for natural gas which in many instances the operator must comply to
- Rates are largely fixed and cannot be adjusted without Commission approval
- In addition to rate, most commissions include other specific pricing structures for other areas that are serviced by the Operator
- Methods for rate adjustment / regulation varies significantly between companies
    - Ex. combination of NYMEX gas futures and actuals (state / provincial rates, S&P Global Platts) applied as a corrective factor against current rates

Mixed[1] *(~25%)*

- Regulated by a state / provincial commission
- Rates may be changed by the Operator but will still require commission approval
- Distinguished in some instances with a supplemental / variable energy charge
- In other instances, rate is not capped but the ROE is
- Retail and wholesale may be treated differently in terms of how rates are managed

1 – Contains elements of both Cost of Service and Incentive

Incentive *(~15%)*

- Regulated by a state / provincial commission
- Commission does not set a yearly rate nor does the Operator need to seek approval
- May include the option for customers to chose between a variable and fixed rate:
    - Variable: Subject to price fluctuations without notice
    - Fixed: Price remains constant for a set period, typically 12 months
- Monthly rate change amendment typically issued to customers

Power Advocate

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]

• [redacted]
• [redacted]
• [redacted]
	• [redacted]
	• [redacted]
	• [redacted]
		• [redacted]
		  – [redacted]
		  – [redacted]
		  – [redacted]
			• [redacted]
			• [redacted]

[redacted]

[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]		
[redacted]		
[redacted]		

[redacted]
[redacted]
[redacted]
[redacted]
[redacted]

Power Advocate

LEGD NPL Bundled vs. Non-Bundled Units Pilot

In order to provide increased budget accuracy / forecasting, LEGD instituted a change order (effective April 2019 through June 2020) intended to minimize the use of appurtenances for Unit Price work:

NPL Share of Shortfall

Enbridge Share of Shortfall

Bundled Unit Fees Paid to ENB (Shortfall -%, Overrun +%)

-10% | -7.5% | -5% | -2.5% | 0% | +2.5% | +5% | +7.5% | +10%

NPL Share of Overrun

Enbridge Share of Overrun

Current [redacted] [redacted] [redacted]

[redacted]

	Toronto	Central		Niagara	Average (%)
Services - Improved	**10**	**20**	**50**	**80**	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

For the O&M asked about in JT4.19, identified in Exhibit I.2.4- EP-8 Table 2 that was allocated to ICM projects as indirect overhead, what adjusting rate mechanism did EGI use to ensure there was no double-counting of these O&M costs for the purpose of making rates?

Response:

Enbridge Gas did not make any adjustment to rates set through the 2019 to 2023 price cap rate-setting mechanism for the indirect overheads allocated to ICM projects. The OEB approved the inclusion of indirect overheads in the funding request for ICM project costs in Enbridge Gas's 2019 Rates application.[1] The ICM project funding request is based on fully burdened costs consistent with the design and allocation of rates in a rebasing year. The inclusion of indirect overheads in the ICM project funding request is consistent with the OEB's ICM policy.[2]

Annual rates set through a price cap rate-setting mechanism are decoupled from costs and there is no adjustment to rates for variability in forecast costs during an IRM term.

[1] EB-2018-0305 Decision and Order, September 12, 2019, p.29.
[2] Ibid.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

JT6.20: We asked, under the 18.5 PJ inventory scenario, if EGI could meet its delivery obligations to non-utility customers and the company provided Table 1. Does the line 2 scenario at 18.5 PJ meet the company's obligations to its Priority of Service schedule?

Response:

The response to Exhibit JT6.20 is in reference to the "deliverability" of the non-utility customers, which was assumed to mean peak storage withdrawals. Assuming the term "delivery obligations" is also referring to storage withdrawals, Enbridge Gas can meet the obligations of its storage services for non-utility customers under that scenario.

As shown in Table 1 of Exhibit JT6.20 under the 18.5 PJ inventory the Company would have a 0.8 PJ/d shortfall on design day for utility customers.

In a scenario whereby deliverability available to serve utility customers would be reduced by 0.8 PJ/d, Enbridge Gas would not be able to meet its obligations to serve firm utility customers. Enbridge Gas would need to replace the 0.8 PJ/d of reduced deliverability with other assets including supply purchases, delivered services, and/or market-based storage services.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Can we be sent a copy of an unredacted JT7.21?

Response:

This can be found in CONFIDENTIAL_EGI_TechUndertakings_20230406.pdf page 239 to 240.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Can the Company provide the contractor actual cost to date for the London Lines?

Response:

The contractor actual cost to date for the London Lines project is $94,365,492.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Populate the provided table, assuming the ALG procedure, to calculate the depreciation provision impact of adopting an alternative average useful life and survivor curve and a change in the discount rate used.

Also, in relation to the inflation "double counting" issue, could Concentric please provide a "written out" calculation of its recommended depreciation provision for Account 452. That is, could they please set out the calculation in a series of equations which illustrate, in particular, how inflation is accounted for, as described at a high level in Concentric's response in I.4.5-Staff-176. It would be most helpful if they could link each such equation to the spreadsheet model provided as Attachment 1 to I.4.5.IGUA-14.

A	B	C	D	E	F
Asset Account	Concentric Recommended Life Curve	Concentric Depreciation Provision (using CARF discount rate @3.75%)	Alternative Recommended Life Curve for Modelling	Calculated Depreciation Provision Change for Alternative Life Curve @ CARF Discount Rate	Calculated Depreciation Provision Change for Alternative Life Curve @ WACC Discount Rate (assume 6.03% for modelling)
452	40-R3		45-R2.5		
453			n/a	0	
455			n/a	0	
456	40-R4		44-R4		
457	35-R3		40-R2.5		
462			n/a	0	
463			n/a	0	
464			n/a	0	
465	60-R4		70-R4		
466	30-R4		37-R4		
467			n/a	0	
472.35	Truncation 2024		No Truncation 40-S0.5		
473.01	45-S1		50-L1		
473.02	55-S3		60-S3		
474	25-SQ		50-L1		
475.21	55-R3		70-R3		
475.3	60-R4		70-R2		
477			n/a	0	
478	15-S2.5		25-L1.5		

491.01 and 491.02 (post 2023)	4-SQ		5-SQ		
TOTALS:		[sum]		[sum]	[sum]

Response:

The following response was provided by Concentric Energy Advisors:
Table 1 below provides the estimated impact of the requested alternatives. Please note these impacts are based on the 2021 asset balances that formed the basis of Concentric's depreciation study for ease of comparability. The impacts would differ in magnitude if the revised rates/assumptions are applied to the 2024 Test Year asset balances.

Table 1
Alternative Depreciation Calculations

Asset Account	Concentric Recommended Life and Curve	Concentric Depreciation Provision TOTAL (using CARF discount rate 3.75%)	Alternative Recommended Life and Curve	Depreciation Provision for Alternative Life and Curve @ CARF Discount Rate TOTAL Change	Depreciation Provision for Alternative Life and Curve @ WACC Discount Rate (6.03%) TOTAL Change
442.00	40-S5	104,018	N/A	-	-
443.01	45-R4	51,698	N/A	-	-
443.02	55-R4	213,953	N/A	-	-
451.00	55-R4	1,070,227	N/A	-	-
452.00	40-R3	3,341,859	45-R2.5	(1,053,046)	(1,239,324)
453.00	45-R2.5	4,539,036	N/A	-	(860,284)
454.00	40-R2	134,706	N/A	-	-
455.00	55-R3	4,498,768	N/A	-	(246,673)
456.00	40-R4	18,069,972	44-R4	(2,778,143)	(3,601,335)
457.00	35-R3	1,752,619	40-R2.5	(450,804)	(578,553)
461.00	60-R4	1,409,557	N/A	-	-
462.00	50-S4	3,276,395	N/A	-	(143,044)
463.00	55-S4	148,411	N/A	-	(8,398)
464.00	50-S4	62,378	N/A	-	(2,915)
465.00	60-R4	45,746,509	70-R4	(9,313,524)	(12,269,725)
466.00	30-R4	34,401,431	37-R4	(9,515,433)	(10,311,121)
467.00	40-R4	11,247,651	N/A	-	(960,745)
471.00	60-R4	1,072,013	N/A	-	-
472.00	40-S0.5	5,155,524	N/A	-	-
472.31	40-S0.5	1,180,276	N/A	-	-
472.32	40-S0.5	885,199	N/A	-	-
472.33	40-S0.5	2,353,163	N/A	-	-
472.34	40-S0.5	628,711	N/A	-	-
472.35	40-S0.5	8,041,884	40-S0.5 - No Truncation	(7,627,722)	(7,627,722)
473.01	45-S1	15,818,533	50-L1	(4,740,643)	(6,795,099)
473.02	55-S3	110,249,554	60-S3	(15,563,480)	(30,900,537)
474.00	25-SQ	43,329,780	50-L1	(33,157,286)	(33,157,286)
475.00	25-SQ	10,469,399	N/A	-	-
475.21	55-R3	97,933,996	70-R3	(37,193,539)	(50,737,563)
475.30	60-R4	87,833,160	70-R2	(24,407,105)	(38,290,145)
476.00	17-S2.5	325,072	N/A	-	-
477.00	40-R2	21,482,552	N/A	-	172,266
477.01	35-R3	4,175,366	N/A	-	-

478.00	15-S2.5	91,419,431	25-L1.5	(62,641,782)	(62,641,782)
482.00	40-R1.5	119,585	N/A	-	-
482.01	40-R1.5	3,290,400	N/A	-	-
482.04	40-R1.5	9,286,662	N/A	-	-
482.05	40-R1.5	1,388,286	N/A	-	-
482.51	40-R1.5	3,364,448	N/A	-	-
482.52	40-R1.5	2,783,764	N/A	-	-
483.00	15-SQ	1,309,316	N/A	-	-
484.00	12-L2.5	5,083,958	N/A	-	-
485.00	17-L1.5	2,793,740	N/A	-	-
486.00	15-SQ	9,529,666	N/A	-	-
487.70	15-SQ	86,895	N/A	-	-
487.80	20-SQ	291,548	N/A	-	-
488.00	10-SQ	2,946,627	N/A	-	-
490.00	4-SQ	4,271,256	N/A	-	-
490.00 (Post 2023)	4-SQ	0	N/A	-	-
490.30	10-SQ	502,763	N/A	-	-
491.01	4-SQ	13,823,969	5-SQ	(3,126,833)	(3,126,833)
491.01 (Post 2023)	4-SQ	0	5-SQ	-	-
491.02	4-SQ	3,990,552	5-SQ	(931,868)	(931,868)
491.02 (Post 2023)	4-SQ	0	5-SQ	-	-
491.03	10-SQ	7,355,375	N/A	-	-
Software Intangibles - 10YR	10-SQ	0	N/A	-	-
491.04	10-SQ	9,153,464	N/A	-	-
TOTAL		**713,795,075**		**(212,501,208)**	**(264,258,686)**

Enbridge Gas notes that applying Emrydia and InterGroup's recommended changes to asset lives under the ALG procedure and a 6.03% WACC would result in an annual net salvage provision of only $5 million. This amount is significantly less than Enbridge Gas's forecasted annual site restoration costs of $60 million (Exhibit I.1.8-STAFF-17 Part f).

<u>Illustration of How Inflation is Accounted for in the CDNS Calculation</u>

This example uses Account 473.02 which can also be found at Exhibit I.4.5-IGUA-14 – Attachment 1.

The following inputs were entered into the calculation:

- <u>Cost of Removal Estimate</u> – 0.5 (cell F3) as determined from the traditional net salvage review provided in the Concentric Depreciation Study Exhibit 4, Tab 5, Schedule 1, Attachment 1 Pages 24 to 34. (Note: the use of -50% was very moderated from the total life historic indications of -168%.)
- <u>Average Age of Retirements</u> - 19.37 (Rounded to 19) – Calculated as a weighted average (based on original costs of the retirement) of the retirement transactions as provided in the Service Life File used in the actuarial analysis.
- <u>Credit Adjusted Risk Free Rate</u> – 3.75%
- <u>Future Inflation Rate</u> – 2.00%

Using the calculations related to the Vintage 1970 (row 20 of the Excel spreadsheet):

- Age, Vintage, Original Cost, and R/L (Remaining Life) are directly extracted from Pages 188 to 293 (Detailed Depreciation Calculations), Section 8 of the Concentric Depreciation Study (Exhibit 4, Tab 5, Schedule 1, Attachment 1) related to the same 1970 Vintage.
- Net Salvage Requirement is calculated as Original Cost X Cost of Removal Estimate = $1,563,798.64X0.5 = $781,899.32. This represents the net salvage requirement calculated in accordance with the Traditional method of net salvage analysis.
- Adjusted Original Cost brings the Vintage original cost forward by the average age of retirement (19 years) using a CPI Inflation Factor calculated by utilizing a CPI factor based on the age of the vintage (3.689). The resultant calculation is equal to $1,563,798.64X3.689 = $5,768,109.74 (Note the same adjustment period is used for all vintages because an average age of all retirement transactions is assumed for all historic retirement years)
- CPI Inflation Factor is based on Statistics Canada published CPI factors using a base year of 2002.
- Adjusted Net Salvage Rate calculates a net salvage ratio that is free of the impacts of inflation as the original cost has been normalized by the period of the average age of retirements. The sample calculation is the net salvage requirement/adjusted original cost ($781,899.32/$5,768,109.74 = 0.14).
- Future Net Salvage Requirement is the inflation adjusted requirement based on the Adjusted Original Cost ($5,768,109.74) X the Adjusted Net Salvage Rate (0.14) inflated by the Future Inflation Rate (2.00%) over the estimated remaining life of the vintage (12.3 years). The resultant calculation is: ($5,768,109.74X0.14)*((1+2.0%)^12.3) = $997,546.04
- Discounted Salvage Requirement represents the Future Salvage Requirement ($997,546.04) discounted at the Credit Adjusted Risk Free Rate (3.75%) back to the study year (12.3 years). The resultant calculation is: $997,546.04/((1+3.75%)^12.3) = $634,277.42
- Resultant CDNS rate to use in depreciation calculations is shown at the bottom of the Discounted Salvage Requirement Column and is calculated by dividing the Sum of the Discounted Salvage requirement for all vintages by the Sum of the Original Cost of all vintages. The resultant calculation is $1,165,570,929.85/$4,458,865,638.83 = 26%

As noted in the above explanation, the Adjusted Original Cost brings the original cost to the same cost base as the Net Salvage Requirement percentage. This is required because the Net Salvage Requirement in 5th column of the working file represents a percentage that has an embedded amount of inflation based on the average age of the retirements. Once the Original cost has been normalized to the same cost base of the cost of removal expenditures, the resultant adjusted net salvage rate represents the ratio of cost of removal to original cost expenditures at the same cost base that has had impacts of inflation removed from the calculation. Therefore, the Adjusted Net Salvage ratio can be used in the determination of the Future Salvage Requirement calculation.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[1.9-SEC-90] Are the productivity savings shown in Table 1 all O&M savings? If not, please provide a breakdown of which savings are capital vs. O&M.

Response:

All productivity savings shown in Exhibit I.1.9-SEC-90 Table 1 are O&M savings.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[1.1-SEC-74] Please breakdown integration savings each year between DSM vs. non-DSM O&M.

a) [4-3-1] Please reconcile the different UFG volumes shown in the evidence:
   i. Historic UFG volumes included in the UFG Progress Report (4-3-1, Attach 3, Figure 2)
   ii. UFG Volumes shown in 4-3-1, Table 3 and 4-3-1, Attach 1
b) Please provide a table that shows for each year since 2013, the total UFG volumes, total throughput, and UFG volumes as a percentage of throughput.
c) Enbridge is proposing a simple 3-year average. Please provide the underlying calculation for the 2024 UFG volume forecast.

Response:

The integration synergies outlined in Exhibit I.1.1-SEC-74 Attachment 1 page 2 are all non-DSM O&M savings.

a) The 2019 Report on Unaccounted for Gas (UFG), prepared by Scott Madden Management Consultants, was filed as part of the 2020 Rate Application Phase 2 proceeding[1]. 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"[2]. The UFG Progress Report was completed in response to that commitment. The UFG Progress Report was originally filed in the 2022 Rate Application[3] and subsequently filed as part of the 2024 Rebasing Application, as Exhibit 4, Tab 3, Schedule 1, Attachment 3.

   The historic UFG volumes shown in Figure 2 of the UFG Progress Report were reported consistent with how UFG volumes were reported in the 2019 Report on UFG, prepared by ScottMadden.

   There are two differences between the historic UFG volumes in Figure 2 from the UFG Progress Report and the UFG Volumes shown in Exhibit 4, Tab 3, Schedule 1, Table 3 and Attachment 1. The first difference is that the 2019 Report on UFG did not include UFG associated with the EGD rate zone storage

[1] EB-2019-0194.
[2] EB-2019-0194, Reply Argument, May 1, 2020, p.22; EB-2019-0194, Decision and Order, May 14, 2020, p.20.
[3] EB-2021-0148.

operations. In the 2022 Rate Application where the 2019 Report on UFG was considered, it was noted that:

> "The UFG reported for Union includes volumes related to distribution, storage and transmission activities. Conversely, the UFG reported for EGD includes only the volumes related to the distribution system in its franchise areas. It does not include gas storage…"[4]

The second difference relates to the allocation of UFG volumes to the non-utility business for the Union Rate Zones. The 2019 Report on UFG reported the total UFG volumes for the Union Rate Zones, which included both utility and non-utility UFG volumes. However, for the purposes of the 2024 Rebasing Application, only utility volumes were reported in Exhibit 4, Tab 3, Schedule 1, Table 3 and Attachment 1.

Please see Table 1 for a reconciliation of UFG volumes between the UFG Progress Report (Exhibit 4, Tab 3, Schedule 1, Attachment 3, Figure 2) and UFG volumes shown in Exhibit 4, Tab 3, Schedule 1, Table 3 and Exhibit 4, Tab 3, Schedule 1, Attachment 1.

[4] EB-2019-0194, Argument in Chief, March 11, 2020, p. 29.

Table 1
Reconciliation of UFG Volumes

Line No.	Particulars (10^3m^3)	Utility	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	UAF / LUF Volumes (1)	EGD	121,125	159,143	112,201	153,478	113,443	162,451	160,960	130,599
2	UFG Utility Volumes (1)	Union	98,596	87,014	47,204	114,166	95,887	121,984	121,079	66,056
3	Total		219,721	246,158	159,405	267,643	209,330	284,435	282,038	196,655
4	UAF Only (2)	EGD	97,361	135,380	88,438	133,112	93,077	142,086	140,594	110,234
5	UFG Utility/Non-Utility Volumes (2)	Union	113,997	97,109	54,408	131,588	108,901	136,447	137,652	74,120
6	Total		211,358	232,489	142,846	264,700	201,978	278,533	278,246	184,354
7	LUF Volumes	EGD	23,764	23,764	23,764	20,365	20,365	20,365	20,365	20,365
8	UFG Non-Utility Volumes	Union	15,401	10,095	7,204	17,422	13,014	14,463	16,573	8,064

Notes:
(1) Exhibit 4, Tab 3, Schedule 1, Attachment 1.
(2) Exhibit 4, Tab 3, Schedule 1, Attachment 3, Figure 2.

b) Please see Table 2 below for UFG volumes, total throughput and UFG as a percentage of throughput.

Table 2
UFG Volumes, Throughput and UFG as a Percentage of Throughput

Line No.	Particulars (10^3m^3)	Utility	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual (3)	2019 Actual	2020 Actual	2021 Actual	2022 Actual (4)
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	UAF / LUF Volumes	EGD (1)	121,125	159,143	112,201	153,478	113,443	162,451	160,960	130,599	135,918	276,698
2	UFG Volumes	Union (2)	98,596	87,014	47,204	114,166	95,887	121,984	121,079	66,056	223,637	218,904
3	Total		219,721	246,158	159,405	267,643	209,330	284,435	282,038	196,655	359,555	495,602
6	Total Throughput	EGI	47,947,642	43,934,920	43,938,929	42,359,970	43,375,046	49,032,466	49,748,774	47,593,775	49,566,637	55,442,436
7	UFG %	EGI	0.458%	0.560%	0.363%	0.632%	0.483%	0.580%	0.567%	0.413%	0.725%	0.894%

Notes:
(1) EGD rate zone.
(2) Union rate zones.
(3) 2018 Total Throughput has been updated to correct an error in Exhibit I.4.3-ED-133 Attachment 3, p.1.
(4) 2022 Actual UFG Volumes reflect final balances to be filed in Enbridge Gas's 2022 Utility Earnings and Disposition of Deferral and Variance Account Balances Application.

c) As provided in Exhibit I.4.3-LPMA-30 part b) and c):

Table 3
Determination of 2024 Enbridge Gas UFG Forecast

Line No.	Particulars (10^3m^3)	EGI (Utility) (1)	Non-Utility	EGI (Total Utility)
		(a)	(b)	(c)
1	2019	282,038	21,874	303,912
2	2020	196,655	13,365	210,020
3	2021	359,555	34,246	393,801
4	Forecasted UFG volume for 2024 (3-year average)	279,416	23,162	302,578
5	Non-Utility - 10.6445% (2)			32,208
6	Forecasted Utility UFG volume for 2024			270,370

Notes:
(1) Exhibit 4, Tab 3, Schedule 1, Table 3, line 4.
(2) Allocation calculated based on proposed methodology Exhibit 1, Tab 13, Schedule 2, Section 2.4. This evidence will be addressed in Phase 2 of the proceeding as noted in Enbridge Gas's February 1, 2023 letter.

The 2024 Utility UFG Forecast of 270,370 10^3m^3 is calculated by taking the 3-year simple average of the Total Utility UFG volumes for 2019 to 2021 less the allocation of non-utility UFG volumes as shown in column (c) in Table 2. This differs from the 3-year simple average of Utility volumes in column (a) line 4 of 279,416 in Table 3.

Enbridge Gas operates its assets on an integrated basis and does not operationally segregate them as utility vs non-utility. As such, Total Utility UFG is more indicative of expected UFG volumes. On that basis, it is appropriate to use the 3-year simple average of Total Utility UFG and then apply an allocation of non-utility UFG to determine the forecast of utility UFG volumes.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[Ex.4-4-3, Table 3] What depreciation methodology does Central Function (CF) use (e.g. ALG, ELG etc)?

Response:

ALG and ELG are group methods of depreciation. Group methods of depreciation are not applied to CF shared assets. Rather, CF shared assets are depreciated at a single asset level and depreciation amounts for each shared asset are determined using the straight-line depreciation method over the estimated useful life of each asset.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[JT 5.2] Please provide a revised 2024 rate base calculation based on the deferral/cancellation of 2023 projects shown in JT 5.2.

Response:

Removing the 2023 cancelled/deferred projects as shown in Exhibit JT5.2 results in a $269.3 million reduction to 2024 Rate Base (from $16,281.1 million to $16,011.8 million). This reduction was quantified using simplifying assumptions (outlined below) for illustrative purposes only in response to the question. The actual rate base impact would differ as the cancellation/deferral of these projects would lead to changes in the timing and scope of other projects in the Asset Management Plan. As discussed on Day 5 of the Technical Conference (Page 10, Line 7), work on the 2024 budget is underway.

The following simplifying assumptions were made in calculating the impact noted above:

- Capital spend was used as a proxy for in-service additions.
- No changes to retirements were forecasted for the revised calculation.
- Total plant composite depreciation rates were used instead of asset specific depreciation rates.
- No projects were forecasted to replace the 2023 cancelled/deferred projects, although as stated above there would be changes to the timing and scope of other projects in the Asset Management Plan.
- All 2023 projects were assumed to be cancelled, and there was no assumption that the projects would be deferred to 2024, although some projects may be deferred to 2024.
- Estimated reduction includes overhead capitalization which would be re-allocated to other projects rather than cancelled/deferred.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Does Enbridge Gas Inc. provide services to any affiliates? If so, please provide details including how those costs are recovered and where that is shown in the evidence.

Response:

Services to Affiliates

Enbridge Gas provides services to affiliates such as: business development, engineering, operations, and regulatory. EGI employees who work in a Central Functions department may also provide services to affiliates, such as finance, legal, and supply chain.

As described in Exhibit 4, Tab 4, Schedule 3, paragraph 85, Enbridge Gas performs these services and incurs expenses on behalf of affiliates, which are subsequently reimbursed and recovered from affiliates. Expenses and recoveries for these services are based on the cost of actual services provided (where applicable) or on a fully allocated cost basis. Affiliate reimbursements of expenses from 2018 to 2024 are shown in Exhibit I.4.4-VECC-53 Table 1. Amounts recovered from affiliates are credited to O&M.

Table 1 below outlines the recoveries received for the services Enbridge Gas provides to affiliates.

Table 1
2022 Enbridge Gas Services Provided to Affiliates

Line No.	Particulars ($ millions)	2099634 Ontario Limited	Gazifère Inc.	2193914 Canada Limited	Enbridge Inc.	Niagara Gas Transmission Limited	Other Affiliates	Total Recoveries by Service
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Business Development	0.6	0.0	-	-	0.0	0.2	0.9
2	Finance	-	0.2	0.1	-	0.1	0.2	0.6
3	Engineering	0.1	0.1	0.3	0.0	0.2	0.4	1.1
4	Technology Information Services	-	-	-	1.4	-	-	1.4
5	Energy Services	-	0.3	0.0	-	0.1	0.2	0.7
6	Other	0.0	0.1	0.0	-	0.0	0.0	0.2
7	Total Recoveries by Affiliate	0.8	0.8	0.4	1.4	0.4	1.0	4.8

Revenue from Transactions with Affiliates

Enbridge Gas provides distribution, storage and transportation services to affiliates pursuant to OEB approved rates. These revenues are recorded within the distribution, transportation and storage components of utility operating revenues found in Exhibit 3, Tab 1, Schedule 1.

As outlined in Exhibit I.1.6-FRPO-5, Enbridge Gas also has regulated revenue transactions which are negotiated directly with affiliates. These revenues are recorded within the storage and transportation and upstream transportation optimization components of utility operating revenues found in Exhibit 3, Tab 4, Schedule 1. Enbridge Gas also receives revenues from affiliates related to operating leases of real estate assets. These revenues are recorded within other operating revenue found at Exhibit 3, Tab 5, Schedule 1.

Table 2 below outlines the utility revenues received from Enbridge Gas affiliates in 2022.

Table 2
Enbridge Gas Affiliate Revenues

Line No.	Particulars ($ millions)	2022
		(a)
1	Gazifère Inc.	42.8
2	Tidal Energy Marketing Inc.	11.6
3	Other Affiliates	0.9
4	Total Distribution, Storage and Transportation Affiliate Revenues	55.3
5	2562961 Ontario Ltd.	0.2
6	Total Affiliate Lease Revenues	0.2
7	Total Affiliate Revenues	55.5

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[Ex.8] For each of EGD, Union North, and Union South rate zones, please provide a table that shows the annual delivery rates (including base rates, ICM rate riders, and Y-Factors) for each year since 2012.

Response:

Please see Attachment 1 - Summary from 2012 to 2023 - All Three Rate Zones.

2012 to 2023 Annual Delivery Rates
EGD Rate Zone

Line No.	Particulars (cents/m^3)	2023 EB-2022-0286 January 1, 2023	2022 EB-2022-0219 October 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (1) EB-2018-0305 November 1, 2019	2018 EB-2018-0249 October 1, 2018	2017 EB-2017-0281 October 1, 2017	2016 EB-2016-0260 October 1, 2016	2015 EB-2015-0242 October 1, 2015	2014 EB-2014-0191 October 1, 2014	2013 EB-2013-0295 October 1, 2013	2012 EB-2012-0352 October 1, 2012
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate 1												
1	Monthly Customer Charge (2)	$21.88	$21.12	$20.83	$20.48	$20.21	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
	Delivery Charge per cubic metre												
2	For the first 30 m^3 per month	10.6988	10.2567	9.7651	9.7072	9.4710	9.5938	8.5010	8.1715	7.3025	6.7766	7.2856	7.0977
3	For the next 55 m^3 per month	10.0142	9.6036	9.1455	9.0910	8.8718	8.9757	7.9534	7.6451	6.8320	6.3400	6.8163	6.6405
4	For the next 85 m^3 per month	9.4781	9.0922	8.6604	8.6086	8.4026	8.4916	7.5244	7.2328	6.4636	5.9981	6.4485	6.2822
5	For all over 170 m^3 per month	9.0785	8.7110	8.2987	8.2489	8.0528	8.1308	7.2048	6.9256	6.1890	5.7432	6.1746	6.0154
6	Gas Supply Load Balancing	2.1889	2.5417	1.2519	1.1398	1.2268	1.6642	1.5267	1.6558	1.1431	0.7564	0.9043	1.0951
7	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2588	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
8	Gas Supply Transportation Dawn (3)	0.9681	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
	Rate 6												
9	Monthly Customer Charge (2)	$76.58	$73.91	$72.89	$71.68	$70.75	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00
	Delivery Charge per cubic metre												
10	For the first 500 m^3 per month	10.1355	10.2005	9.3466	9.0781	8.7829	8.9813	8.2106	8.0119	7.3605	7.0389	7.2760	6.9233
11	For the next 1050 m^3 per month	7.7428	7.7878	7.1517	6.9515	6.7327	6.8659	6.2767	6.1249	5.6269	5.3809	5.5622	5.2925
12	For the next 4500 m^3 per month	6.0672	6.0982	5.6147	5.4623	5.2970	5.3846	4.9225	4.8035	4.4129	4.2200	4.3623	4.1508
13	For the next 7000 m^3 per month	4.9907	5.0127	4.6272	4.5056	4.3746	4.4329	4.0524	3.9544	3.6328	3.4740	3.5910	3.4170
14	For the next 15250 m^3 per month	4.5123	4.5304	4.1884	4.0804	3.9647	4.0100	3.6659	3.5772	3.2863	3.1426	3.2486	3.0910
15	For all over 28300 m^3 per month	4.3922	4.4092	4.0782	3.9737	3.8617	3.9038	3.5687	3.4824	3.1993	3.0595	3.1626	3.0093
16	Gas Supply Load Balancing	2.0221	2.3450	1.1669	1.0630	1.1416	1.5422	1.4066	1.5439	1.0532	0.6311	0.7476	0.9148
17	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2588	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
18	Gas Supply Transportation Dawn (3)	0.9681	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
	Rate 9												
19	Monthly Customer Charge (2)	$258.11	$249.15	$245.71	$241.60	$238.47	$235.95	$235.95	$235.95	$235.95	$235.95	$235.95	$235.95
	Delivery Charge per cubic metre												
20	For the first 20,000 m^3 per month	12.3268	11.9085	11.7249	11.5228	11.3720	11.2489	10.9204	10.6625	10.5854	10.3615	10.7735	10.7426
21	For all over 20,000 m^3 per month	11.5395	11.1485	10.9755	10.7859	10.6446	10.5292	10.2218	9.9804	9.9081	9.6986	10.0844	10.0553
22	Gas Supply Load Balancing	0.0277	0.0316	0.0155	0.0139	0.0147	0.0196	0.0179	0.0185	0.0136	0.0170	0.0000	0.0053
23	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
24	Gas Supply Transportation Dawn (3)	0.9681	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
	Rate 100												
25	Monthly Customer Charge (2)	$133.47	$128.83	$127.05	$124.93	$123.32	$122.01	$122.01	$122.01	$122.01	$122.01	$122.01	$122.01
	Delivery Charge												
26	Per cubic metre of Contract Demand	39.6129	38.2444	37.5887	36.9620	36.3852	36.0000	36.0000	36.0000	36.0000	36.0000	8.1900	8.1900
	Per cubic metre of gas delivered												
27	For the first 14,000 m^3 per month	0.1932	0.2025	0.1829	0.1766	0.1747	0.1771	0.1729	0.1547	0.1576	0.1729	5.0951	5.0132
28	For the next 28,000 m^3 per month	0.1932	0.2025	0.1829	0.1766	0.1747	0.1771	0.1729	0.1547	0.1576	0.1729	3.7361	3.6542
29	For all over 42,000 m^3 per month	0.1932	0.2025	0.1829	0.1766	0.1747	0.1771	0.1729	0.1547	0.1576	0.1729	3.1771	3.0952
30	Gas Supply Load Balancing	2.0221	2.3450	1.1669	1.0630	1.1416	1.5422	1.4066	1.5439	1.0532	0.6311	0.4948	0.5960
31	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
32	Gas Supply Transportation Dawn (3)	0.9681	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A

2012 to 2023 Annual Delivery Rates
EGD Rate Zone

Line No.	Particulars (cents/m³)	2023	2022	2021	2020	2019 (1)	2018	2017	2016	2015	2014	2013	2012
		EB-2022-0286	EB-2022-0219	EB-2021-0219	EB-2020-0195	EB-2018-0305	EB-2018-0249	EB-2017-0281	EB-2016-0260	EB-2015-0242	EB-2014-0191	EB-2013-0295	EB-2012-0352
		January 1, 2023	October 1, 2022	October 1, 2021	October 1, 2020	November 1, 2019	October 1, 2018	October 1, 2017	October 1, 2016	October 1, 2015	October 1, 2014	October 1, 2013	October 1, 2012
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate 110												
33	Monthly Customer Charge (2)	$642.55	$620.22	$611.66	$601.43	$593.65	$587.37	$587.37	$587.37	$587.37	$587.37	$587.37	$587.37
	Delivery Charge												
34	Per cubic metre of Contract Demand	25.3940	24.5231	23.9866	23.5878	23.1551	22.9100	22.9100	22.9100	22.9100	22.9100	22.9100	22.9100
	Per cubic metre of gas delivered												
35	For the first 1,000,000 m³ per month	1.0915	1.1397	0.9053	0.8538	0.8333	0.8549	0.7449	0.7240	0.5693	0.5584	0.5834	0.5201
36	For all over 1,000,000 m³ per month	0.9236	0.9783	0.7467	0.6985	0.6808	0.7049	0.5949	0.5740	0.4193	0.4084	0.4334	0.3701
37	Gas Supply Load Balancing	0.4290	0.5011	0.2425	0.2179	0.2344	0.3237	0.2974	0.3039	0.2056	0.0945	0.1552	0.1651
38	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
39	Gas Supply Transportation Dawn (3)	0.9681	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
	Rate 115												
40	Monthly Customer Charge (2)	$681.11	$657.44	$648.36	$637.53	$629.28	$622.62	$622.62	$622.62	$622.62	$622.62	$622.62	$622.62
	Delivery Charge												
41	Per cubic metre of Contract Demand	27.1243	26.1983	25.5390	25.1149	24.6207	24.3600	24.3600	24.3600	24.3600	24.3600	24.3600	24.3600
	Per cubic metre of gas delivered												
42	For the first 1,000,000 m³ per month	0.7281	0.8091	0.5200	0.4782	0.4414	0.4325	0.3733	0.3663	0.2181	0.2069	0.2104	0.1956
43	For all over 1,000,000 m³ per month	0.6257	0.7072	0.4188	0.3774	0.3409	0.3325	0.2733	0.2663	0.1181	0.1069	0.1104	0.0956
44	Gas Supply Load Balancing	0.1476	0.1687	0.0918	0.0847	0.0897	0.1159	0.1071	0.1093	0.0814	0.0449	0.0487	0.0568
45	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
46	Gas Supply Transportation Dawn (3)	0.9681	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
	Rate 125												
47	Monthly Customer Charge (2)	$546.97	$527.96	$520.67	$511.97	$505.35	$500.00	$500.00	$500.00	$500.00	$500.00	$500.00	$500.00
	Delivery Charge												
48	Per cubic metre of Contract Demand	11.2127	10.7838	10.6389	10.4657	10.1505	9.8840	9.7583	9.0962	8.2361	8.0942	9.0982	9.1119
	Rate 135												
49	Monthly Customer Charge (2)	$125.89	$121.52	$119.84	$117.84	$116.31	$115.08	$115.08	$115.08	$115.08	$115.08	$115.08	$115.08
	Delivery Charge per cubic metre of gas delivered												
	December to March												
50	For the first 14,000 m³ per month	8.7639	8.2746	7.8043	7.5200	7.3244	7.1599	7.0979	7.0941	6.7146	6.6924	6.7006	6.6899
51	For the next 28,000 m³ per month	7.2875	6.9146	6.4921	6.2574	6.0949	5.9599	5.8979	5.8941	5.5146	5.4924	5.5006	5.4899
52	For all over 42,000 m³ per month	6.7024	6.4133	6.0259	5.8256	5.6848	5.5599	5.4979	5.4941	5.1146	5.0924	5.1006	5.0899
	April to November												
53	For the first 14,000 m³ per month	3.0755	2.9629	2.6470	2.5264	2.4429	2.4599	2.3979	2.3941	2.0146	1.9924	2.0006	1.9899
54	For the next 28,000 m³ per month	2.2402	2.1870	1.8954	1.8004	1.7343	1.7599	1.6979	1.6941	1.3146	1.2924	1.3006	1.2899
55	For all over 42,000 m³ per month	1.9844	1.9565	1.6755	1.5911	1.5319	1.5599	1.4979	1.4941	1.1146	1.0924	1.1006	1.0899
56	Gas Supply Load Balancing	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
57	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2588	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
58	Gas Supply Transportation Dawn (3)	0.9682	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A

2012 to 2023 Annual Delivery Rates
EGD Rate Zone

Line No.	Particulars (cents/m³)	2023 EB-2022-0286 January 1, 2023	2022 EB-2022-0219 October 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (1) EB-2018-0305 November 1, 2019	2018 EB-2018-0249 October 1, 2018	2017 EB-2017-0281 October 1, 2017	2016 EB-2016-0260 October 1, 2016	2015 EB-2015-0242 October 1, 2015	2014 EB-2014-0191 October 1, 2014	2013 EB-2013-0295 October 1, 2013	2012 EB-2012-0352 October 1, 2012
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate 145												
59	Monthly Customer Charge (2)	$134.93	$130.24	$128.44	$126.29	$124.66	$123.34	$123.34	$123.34	$123.34	$123.34	$123.34	$123.34
	Delivery Charge												
60	Per cubic metre of Contract Demand	9.0517	8.7389	8.5968	8.4535	8.3181	8.2300	8.2300	8.2300	8.2300	8.2300	8.2300	8.2300
	Per cubic metre of gas delivered												
61	For the first 14,000 m³ per month	7.5438	6.5522	5.4334	3.6210	3.0957	3.0046	2.9780	2.9419	2.6374	2.7809	2.8008	2.7387
62	For the next 28,000 m³ per month	6.1695	5.1781	4.0592	2.2473	1.7248	1.6456	1.6190	1.5829	1.2784	1.4219	1.4418	1.3797
63	For all over 42,000 m³ per month	5.6040	4.6127	3.4938	1.6821	1.1607	1.0866	1.0600	1.0239	0.7194	0.8629	0.8828	0.8207
64	Gas Supply Load Balancing	21.2325	1.0973	0.5459	0.4933	0.5283	0.7187	0.6259	0.6618	0.4859	0.1739	0.1853	0.1870
65	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2588	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
66	Gas Supply Transportation Dawn (3)	0.9681	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
	Rate 170												
67	Monthly Customer Charge (2)	$305.55	$294.93	$290.86	$286.00	$282.30	$279.31	$279.31	$279.31	$279.31	$279.31	$279.31	$279.31
	Delivery Charge												
68	Per cubic metre of Contract Demand	4.4945	4.3390	4.2673	4.1961	4.1338	4.0900	4.0900	4.0900	4.0900	4.0900	4.0900	4.0900
	Per cubic metre of gas delivered												
69	For the first 1,000,000 m³ per month	0.6569	0.9236	0.6128	0.5626	0.4068	0.5530	0.5101	0.5064	0.3968	0.4912	0.4858	0.4756
70	For all over 1,000,000 m³ per month	0.4529	0.7200	0.4094	0.3595	0.2051	0.3530	0.3101	0.3064	0.1968	0.2912	0.2858	0.2756
71	Gas Supply Load Balancing	0.4153	0.4841	0.2370	0.2135	0.2291	0.3145	0.2897	0.3159	0.2592	0.0965	0.1034	0.1061
72	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
73	Gas Supply Transportation Dawn (3)	0.9681	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
	Rate 200												
74	Monthly Customer Charge - Maximum	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00
	Delivery Charge												
75	Per cubic metre of Firm Contract Demand	16.2592	15.7004	15.4861	15.2302	14.8573	14.7000	14.7000	14.7000	14.7000	14.7000	14.7000	14.7000
76	Per cubic metre of gas delivered	1.4257	1.5295	1.3080	1.2033	1.1839	1.2394	1.1327	1.0976	1.1953	1.2818	1.2815	1.1941
77	Gas Supply Load Balancing	1.9108	2.2217	1.0960	0.9933	1.0668	1.4523	1.2546	1.3345	0.8634	0.4253	0.5507	0.6784
78	Gas Supply Transportation	5.0933	5.2075	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
79	Gas Supply Transportation Dawn (3)	0.9681	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A

Notes:
(1) Annual rates for 2019 were implemented November 1, 2019.
(2) The monthly customer charge excludes the $1 per month charge for Bill 32.
(3) The gas supply transportation Dawn service was implemented in 2017.

2012 to 2023 Annual Delivery Rates
Union North Rate Zone

Line No.	Particulars (cents/m³)	2023 EB-2022-0286 January 1, 2023	2022 EB-2022-0219 October 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (1) EB-2018-0305 November 1, 2019	2018 EB-2018-0253 October 1, 2018	2017 (2) EB-2017-0278 October 1, 2017	2016 EB-2016-0247 October 1, 2016	2015 EB-2015-0255 October 1, 2015	2014 EB-2014-0208 October 1, 2014	2013 EB-2013-0316 October 1, 2013	2012 EB-2012-0345 October 1, 2012
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate 01												
1	Monthly Charge - All Zones (3)	$22.98	$22.18	$21.87	$21.50	$21.22	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00
	Monthly Delivery Charge - All Zones												
2	First 100 m³	11.3210	10.6557	9.9079	9.5316	9.4044	9.3755	9.1537	8.9080	9.0309	9.1540	9.6435	7.5251
3	Next 200 m³	11.0437	10.3985	9.6573	9.2870	9.1622	9.1356	8.9207	8.6825	8.8028	8.8074	9.1190	7.0146
4	Next 200 m³	10.6040	9.9910	9.2604	8.8999	8.7792	8.7563	8.5530	8.3287	8.4451	8.4507	8.7463	6.6519
5	Next 500 m³	10.2007	9.6171	8.8962	8.5446	8.4275	8.4081	8.2155	8.0040	8.1168	8.1233	8.4043	6.3191
6	Over 1,000 m³	9.8671	9.3080	8.5952	8.2510	8.1369	8.1204	7.9367	7.7358	7.8457	7.8529	8.1218	6.0442
	Gas Transportation Service												
7	Union North West Zone (previously Fort Frances)	3.7434	4.6563	4.6613	5.4837	5.4855	6.6802	6.8585	5.8185	5.7686	4.1399	4.3403	5.8897
8	Union North West Zone (previously Western Zone)	3.7434	4.6563	4.6613	5.4837	5.4855	6.6802	6.8585	4.9868	4.9541	4.0901	4.2882	6.2981
9	Union North East Zone (previously Northern Zone)	2.1564	2.3723	2.3084	2.0792	2.0793	2.7516	3.0002	6.4915	6.4503	5.3079	5.5650	7.6495
10	Union North East Zone (previously Eastern Zone)	2.1564	2.3723	2.3084	2.0792	2.0793	2.7516	3.0002	7.7619	7.7149	6.0365	6.3288	8.7597
	Storage Service												
11	Union North West Zone (previously Fort Frances)	2.2731	2.1836	2.0785	2.0265	2.0231	2.2005	2.0547	3.6786	3.6175	2.0636	2.1507	1.8724
12	Union North West Zone (previously Western Zone)	2.2731	2.1836	2.0785	2.0265	2.0231	2.2005	2.0547	3.3463	3.2920	2.2941	2.3910	1.8700
13	Union North East Zone (previously Northern Zone)	6.1436	5.9294	5.8201	5.0081	5.0482	6.3909	6.6690	3.9476	3.8899	3.0945	3.2252	2.2540
14	Union North East Zone (previously Eastern Zone)	6.1436	5.9294	5.8201	5.0081	5.0482	6.3909	6.6690	4.4552	4.3952	3.4348	3.5799	2.5640
	Rate 10												
15	Monthly Charge - All Zones (3)	$76.58	$73.92	$72.90	$71.68	$70.75	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00
	Monthly Delivery Charge - All Zones												
16	First 1,000 m³	10.3286	9.5014	8.5108	8.3429	8.3869	7.9011	7.6688	7.2298	7.1390	7.2431	7.6318	6.0549
17	Next 9,000 m³	8.4675	7.8083	6.9247	6.7677	6.7990	6.4155	6.2363	5.8947	5.8241	5.9134	6.2182	4.7882
18	Next 20,000 m³	7.3888	6.8433	6.0384	5.9082	5.9715	5.7447	5.5647	5.2108	5.1033	5.1639	5.4120	4.0657
19	Next 70,000 m³	6.7116	6.2258	5.4583	5.3299	5.3848	5.1855	5.0279	4.7160	4.6205	4.6776	4.8959	3.6033
20	Over 100,000 m³	4.1456	3.8860	3.2598	3.1388	3.1615	3.0670	2.9942	2.8414	2.7914	2.8353	2.9407	1.8512
	Gas Transportation Service												
21	Union North West Zone (previously Fort Frances)	3.2899	4.1038	4.0863	4.8013	4.8011	5.8487	6.0054	5.1333	5.0913	3.6363	3.8695	5.4555
22	Union North West Zone (previously Western Zone)	3.2899	4.1038	4.0863	4.8013	4.8011	5.8487	6.0054	4.3016	4.2768	3.5873	3.8173	5.8639
23	Union North East Zone (previously Northern Zone)	1.9834	2.1841	2.1170	1.9020	1.8993	2.5218	2.7620	5.8063	5.7729	4.7871	5.0941	7.2153
24	Union North East Zone (previously Eastern Zone)	1.9834	2.1841	2.1170	1.9020	1.8993	2.5218	2.7620	7.0767	7.0376	5.5049	5.8579	8.3255
	Storage Service												
25	Union North West Zone (previously Fort Frances)	1.8108	1.7073	1.5189	1.5007	1.5184	1.6596	1.5437	2.4007	2.3829	1.1356	1.2015	1.1964
26	Union North West Zone (previously Western Zone)	1.8108	1.7073	1.5189	1.5007	1.5184	1.6596	1.5437	2.0684	2.0574	1.3627	1.4418	1.1941
27	Union North East Zone (previously Northern Zone)	4.5974	4.3378	4.0114	3.5148	3.5922	4.5520	4.7078	2.6697	2.6553	2.1512	2.2760	1.5796
28	Union North East Zone (previously Eastern Zone)	4.5974	4.3378	4.0114	3.5148	3.5922	4.5520	4.7078	3.1773	3.1606	2.4865	2.6307	1.8907
	Rate 20												
29	Monthly Charge (3)	$1,090.76	$1,042.67	$1,016.90	$986.42	$958.77	$860.69	$884.46	$932.79	$972.44	$987.27	$1,000.00	$777.19
	Delivery Demand Charge												
30	First 70,000 m³	34.7968	33.8043	33.3824	32.7557	32.2947	28.6515	28.6326	29.3047	27.8909	27.8830	27.8179	20.0760
31	All over 70,000 m³	20.4623	19.8786	19.6305	19.2619	18.9909	16.8485	16.8374	17.2326	16.4012	16.3966	16.3583	11.8057
	Delivery Commodity Charge												
32	First 852,000 m³	0.8017	0.8133	0.7425	0.7057	0.6942	0.5384	0.5495	0.5891	0.5383	0.5423	0.5246	0.2617
33	All over 852,000 m³	0.5923	0.6063	0.5337	0.5013	0.4918	0.3843	0.3952	0.4282	0.3922	0.3963	0.3803	0.1891
	Monthly Gas Supply Demand Charge												
34	Union North West Zone (previously Fort Frances)	37.0463	43.7694	42.4566	47.9510	45.7852	56.0632	56.4242	55.7556	54.0801	21.9979	21.9979	49.3344
35	Union North West Zone (previously Western Zone)	37.0463	43.7694	42.4566	47.9510	45.7852	56.0632	56.4242	34.5138	33.2652	24.8383	24.8397	57.0166
36	Union North East Zone (previously Northern Zone)	42.1468	44.7516	42.9973	39.7379	37.6082	47.6267	50.1792	72.9435	71.4880	62.6086	62.6121	86.6848
37	Union North East Zone (previously Eastern Zone)	42.1468	44.7516	42.9973	39.7379	37.6082	47.6267	50.1792	105.4062	103.7960	82.3638	82.3684	110.8603
	Gas Supply Commodity Transportation 1												
38	Union North West Zone (previously Fort Frances)	2.1707	2.6479	2.5643	2.9283	2.9194	3.5201	3.6200	4.4802	4.3859	3.0513	3.0513	4.2612
39	Union North West Zone (previously Western Zone)	2.1707	2.6479	2.5643	2.9283	2.9194	3.5201	3.6200	4.0146	3.9299	3.1266	3.1266	4.4236
40	Union North East Zone (previously Northern Zone)	1.6398	1.8291	1.7768	1.2942	1.2954	2.2174	2.6498	4.8570	4.7675	3.9709	3.9709	5.1192
41	Union North East Zone (previously Eastern Zone)	1.6398	1.8291	1.7768	1.2942	1.2954	2.2174	2.6498	5.5682	5.4755	4.4184	4.4184	5.6884
	Gas Supply Commodity Transportation 2												
42	Union North West Zone (previously Fort Frances)	-	-	-	-	-	-	-	-	-	-	-	0.2893
43	Union North West Zone (previously Western Zone)	-	-	-	-	-	-	-	-	-	-	-	0.2668
44	Union North East Zone (previously Northern Zone)	-	-	-	-	-	-	-	-	-	-	-	0.4111
45	Union North East Zone (previously Eastern Zone)	-	-	-	-	-	-	-	-	-	-	-	0.5383
	Bundled Storage Service ($/GJ)												
46	Monthly Demand Charge	18.521	18.587	18.501	16.456	16.360	19.093	20.238	12.489	12.366	9.692	9.643	11.097
47	Commodity Charge	0.249	0.254	0.223	0.212	0.207	0.208	0.204	0.159	0.158	0.157	0.156	0.239

2012 to 2023 Annual Delivery Rates
Union North Rate Zone

Line No.	Particulars (cents/m³)	2023 EB-2022-0286 January 1, 2023	2022 EB-2022-0219 October 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (1) EB-2018-0305 November 1, 2019	2018 EB-2018-0253 October 1, 2018	2017 (2) EB-2017-0278 October 1, 2017	2016 EB-2016-0247 October 1, 2016	2015 EB-2015-0255 October 1, 2015	2014 EB-2014-0208 October 1, 2014	2013 EB-2013-0316 October 1, 2013	2012 EB-2012-0345 October 1, 2012
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate 25												
48	Monthly Charge	$368.56	$350.19	$339.91	$327.82	$316.83	$289.76	$306.75	$331.70	$352.32	$360.72	$375.00	$189.32
	Delivery Charge - All Zones (1)												
49	Maximum	6.8338	6.3160	5.5703	5.4426	5.4792	5.2439	5.0909	4.7943	4.7185	4.7842	5.0206	3.7255
	Rate 100												
50	Monthly Charge (3)	$1,620.86	$1,553.83	$1,520.96	$1,482.00	$1,448.19	$1,341.41	$1,372.75	$1,423.71	$1,464.29	$1,477.44	$1,500.00	$777.19
	Delivery Demand Charge												
51	All Zones	19.9460	19.1421	18.9922	18.7270	18.5612	15.0877	15.1083	15.5220	15.3958	15.3755	15.3415	11.9158
	Delivery Commodity Charge												
52	All Zones	0.2875	0.2772	0.2727	0.2682	0.2660	0.2200	0.2205	0.2252	0.2190	0.2162	0.2136	0.1595
	Monthly Gas Supply Demand Charge												
53	Union North West Zone (previously Fort Frances)	63.7313	79.9636	78.5253	91.3301	90.5780	109.9130	114.2215	103.8605	102.9596	59.0298	59.0298	88.0846
54	Union North West Zone (previously Western Zone)	63.7313	79.9636	78.5253	91.3301	90.5780	109.9130	114.2215	79.0784	78.6756	62.3453	62.3453	97.0663
55	Union North East Zone (previously Northern Zone)	99.5339	120.1986	118.3621	125.8639	124.8695	154.8340	161.5404	123.9130	123.2688	106.4130	106.4130	131.6881
56	Union North East Zone (previously Eastern Zone)	99.5339	120.1986	118.3621	125.8639	124.8695	154.8340	161.5404	161.7862	160.9615	129.4620	129.4620	159.8951
	Gas Supply Commodity Transportation 1												
57	Union North West Zone (previously Fort Frances)	3.5750	4.4856	4.4026	5.1144	5.0723	6.1684	6.4075	7.1222	7.0810	5.4887	5.4887	7.8681
58	Union North West Zone (previously Western Zone)	3.5750	4.4856	4.4026	5.1144	5.0723	6.1684	6.4075	6.7730	6.7390	5.5452	5.5452	7.9899
59	Union North East Zone (previously Northern Zone)	5.6921	6.8739	6.7654	7.1855	7.1288	8.8587	9.2385	7.4048	7.3672	6.1784	6.1784	8.5116
60	Union North East Zone (previously Eastern Zone)	5.6921	6.8739	6.7654	7.1855	7.1288	8.8587	9.2385	7.9382	7.8982	6.5140	6.5140	8.9385
	Gas Supply Commodity Transportation 2												
61	Union North West Zone (previously Fort Frances)	-	-	-	-	-	-	-	-	-	-	-	0.2893
62	Union North West Zone (previously Western Zone)	-	-	-	-	-	-	-	-	-	-	-	0.2668
63	Union North East Zone (previously Northern Zone)	-	-	-	-	-	-	-	-	-	-	-	0.4111
64	Union North East Zone (previously Eastern Zone)	-	-	-	-	-	-	-	-	-	-	-	0.5383
	Bundled Storage Service ($/GJ)												
65	Monthly Demand Charge	18.521	18.587	18.501	16.456	16.360	19.093	20.238	12.489	12.366	9.692	9.643	11.097
66	Commodity Charge	0.249	0.254	0.223	0.212	0.207	0.208	0.204	0.159	0.158	0.157	0.156	0.239

Notes:
(1) Annual rates for 2019 were implemented November 1, 2019.
(2) In 2017, Cap-and-Trade charges were included in delivery charges within the approved rate schedules. The Cap-and-Trade charges have been excluded from this attachment for comparability.
(3) The monthly customer charge excludes the $1 per month charge for Bill 32.

2012 to 2023 Annual Delivery Rates
Union South Rate Zone

Line No.	Particulars (cents/m³)	2023 EB-2022-0286 January 1, 2023 (a)	2022 EB-2022-0219 October 1, 2022 (b)	2021 EB-2021-0219 October 1, 2021 (c)	2020 EB-2020-0195 October 1, 2020 (d)	2019 (1) EB-2018-0305 November 1, 2019 (e)	2018 EB-2018-0253 October 1, 2018 (f)	2017 (2) EB-2017-0278 October 1, 2017 (g)	2016 EB-2016-0247 October 1, 2016 (h)	2015 EB-2015-0255 October 1, 2015 (i)	2014 EB-2014-0208 October 1, 2014 (j)	2013 EB-2013-0316 October 1, 2013 (k)	2012 EB-2012-0345 October 1, 2012 (l)
	Rate M1												
1	Monthly Charge (3)	$22.98	$22.18	$21.87	$21.50	$21.22	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00
	Monthly Delivery Commodity Charge												
2	First 100 m³	6.6718	6.3359	5.8445	5.4885	5.3290	5.0777	4.6950	4.1132	3.8988	3.8252	3.7286	3.5197
3	Next 150 m³	6.3594	6.0413	5.5598	5.2131	5.0555	4.8140	4.4539	3.9046	3.7017	3.6263	3.5221	3.3252
4	All over 250 m³	5.5529	5.2806	4.8243	4.5020	4.3487	4.1326	3.8309	3.3656	3.1926	3.1298	3.0336	2.8652
5	Storage Service	0.9025	0.8339	0.8018	0.7692	0.7643	0.7331	0.7153	0.7027	0.7416	0.7491	0.7368	0.9735
	Rate M2												
6	Monthly Charge (3)	$76.58	$73.92	$72.90	$71.68	$70.75	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00
	Monthly Delivery Commodity Charge												
7	First 1,000 m³	6.3704	5.8575	5.2510	4.9531	4.9507	5.0510	4.6695	4.0507	3.6124	3.6225	4.0899	3.7162
8	Next 6,000 m³	6.2615	5.7581	5.1579	4.8626	4.8581	4.9552	4.5818	3.9755	3.5455	3.5557	4.0136	3.6373
9	Next 13,000 m³	5.8896	5.4327	4.8662	4.5932	4.6186	4.7739	4.3949	3.7869	3.3563	3.3608	3.7862	3.4022
10	All over 20,000 m³	5.5017	5.0779	4.5329	4.2686	4.2840	4.4236	4.0755	3.5152	3.1163	3.1215	3.5133	3.1201
11	Storage Service	0.8511	0.7589	0.7017	0.6709	0.6730	0.6483	0.6252	0.6161	0.6428	0.6624	0.7550	0.7172
	Rate M4												
	Monthly demand charge:												
12	First 8,450 m³	69.7386	67.0195	65.6379	64.1235	62.1743	61.6487	56.9923	52.9231	47.8404	46.8295	46.6239	45.2527
13	Next 19,700 m³	33.2119	31.9927	31.3732	30.1975	28.6379	27.6418	25.5539	23.7294	21.4504	20.9972	20.9050	19.6336
14	All over 28,150 m³	28.4656	27.4413	26.9208	25.7891	24.2801	23.2229	21.4688	19.9360	18.0214	17.6406	17.5631	16.3047
	Monthly delivery commodity charge:												
15	First block	2.1576	2.1180	1.7054	1.4604	1.4141	1.5493	1.3803	1.2454	1.0353	0.9945	0.9238	0.5564
16	All remaining use	1.0183	1.0264	0.6738	0.5307	0.5085	0.5919	0.5586	0.5301	0.4466	0.4365	0.3860	0.2173
	Interruptible service (4)												
17	Monthly Charge (3)	$755.88	$725.48	$711.40	$694.73	$680.71	$644.34	$654.15	$669.55	$681.21	$683.97		
	Daily delivery commodity charge:												
18	2,400 m³ to 17,000 m³	3.7140	3.6018	3.2443	2.9928	2.8510	3.0257	2.9902	3.0056	2.6539	2.5883		
19	17,000 m³ to 30,000 m³	3.5841	3.4719	3.1144	2.8629	2.7211	2.8958	2.8603	2.8757	2.5240	2.4584		
20	30,000 m³ to 50,000 m³	3.5158	3.4036	3.0461	2.7946	2.6528	2.8275	2.7920	2.8074	2.4557	2.3901		
21	50,000 m³ to 60,000 m³	3.4679	3.3557	2.9982	2.7467	2.6049	2.7796	2.7441	2.7595	2.4078	2.3422		
	Rate M5												
	Firm service												
22	Monthly demand charge	40.5865	40.1849	40.3016	37.6710	36.4546	34.4858	31.7959	30.7027	28.5955	28.3977	28.6252	27.4318
23	Monthly delivery commodity charge	3.0364	2.9770	2.6432	2.4277	2.3100	2.3415	2.3315	2.2944	2.0180	1.9510	1.9007	2.1298
	Interruptible service												
24	Monthly Charge (3)	$755.88	$725.48	$711.40	$694.73	$680.71	$644.34	$654.15	$669.55	$681.21	$683.97	$690.00	$498.20
	Daily delivery commodity charge (5):												
25	2,400 m³ to 17,000 m³	3.7140	3.6018	3.2443	2.9928	2.8510	3.0257	2.9902	3.0056	2.6539	2.5883		
26	17,000 m³ to 30,000 m³	3.5841	3.4719	3.1144	2.8629	2.7211	2.8958	2.8603	2.8757	2.5240	2.4584		
27	30,000 m³ to 50,000 m³	3.5158	3.4036	3.0461	2.7946	2.6528	2.8275	2.7920	2.8074	2.4557	2.3901		
28	50,000 m³ to 60,000 m³	3.4679	3.3557	2.9982	2.7467	2.6049	2.7796	2.7441	2.7595	2.4078	2.3422		
	Rate M7												
	Firm service												
29	Monthly demand charge	33.8388	33.5024	34.7967	34.8069	35.2413	34.6517	30.8246	27.6801	26.3233	25.5491	25.3924	25.1902
30	Monthly delivery commodity charge	0.5936	0.6040	0.3263	0.2483	0.2577	0.3372	0.4161	0.3734	0.3410	0.3249	0.2814	0.0694
	Interruptible service												
	Monthly delivery commodity charge:												
31	Maximum	7.2427	6.5943	6.4518	6.3181	6.4032	6.4334	5.5963	4.9691	4.2954	4.0364	3.9063	2.4356
	Seasonal service												
	Monthly delivery commodity charge:												
32	Maximum	6.9986	6.3502	6.2077	6.0740	6.1591	6.1893	5.3522	4.7250	4.0513	3.7923	3.6622	2.1915
	Rate M9												
33	Monthly demand charge	27.2284	26.2240	26.1582	24.3598	25.1842	23.5428	22.3154	17.4339	16.2405	15.2792	15.1688	16.8055
34	Monthly delivery commodity charge	0.4338	0.4559	0.2059	0.1353	0.1284	0.1569	0.2425	0.1902	0.2019	0.1964	0.1580	0.2152
	Rate M10												
35	Monthly delivery commodity charge	8.8160	8.5189	7.9620	7.6393	7.5095	7.1560	6.7547	5.9327	5.4186	4.9340	5.1133	2.5032

2012 to 2023 Annual Delivery Rates
Union South Rate Zone

Line No.	Particulars (cents/m³)	2023 EB-2022-0286 January 1, 2023	2022 EB-2022-0219 October 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (1) EB-2018-0305 November 1, 2019	2018 EB-2018-0253 October 1, 2018	2017 (2) EB-2017-0278 October 1, 2017	2016 EB-2016-0247 October 1, 2016	2015 EB-2015-0255 October 1, 2015	2014 EB-2014-0208 October 1, 2014	2013 EB-2013-0316 October 1, 2013	2012 EB-2012-0345 October 1, 2012
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate T1												
36	Monthly Charge (3)	$2,155.61	$2,074.16	$2,039.01	$1,997.27	$1,963.32	$1,896.28	$1,905.94	$1,924.04	$1,935.18	$1,932.35	$1,936.13	$1,793.52
	Storage ($ / GJ)												
	Monthly demand charges:												
37	Firm space	0.012	0.012	0.012	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.010
	Firm Injection/Withdrawal Right												
38	Customer provides deliverability inventory	1.473	1.415	1.388	1.355	1.327	1.184	1.186	1.195	1.208	1.210	1.197	1.012
	Commodity charges:												
39	Customer provides compressor fuel - Withdrawal	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	0.007
40	Customer provides compressor fuel - Injection	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	0.007
41	Storage fuel ratio - customer provides fuel	0.445%	0.430%	0.424%	0.417%	0.412%	0.408%	0.406%	0.403%	0.400%	0.397%	0.395%	0.597%
	Transportation (cents / m³)												
42	Monthly demand charge first 28,150 m³	44.5954	43.5565	43.3948	42.4963	41.3430	40.5921	35.4376	32.5602	32.7527	32.1516	31.9554	19.0307
43	Monthly demand charge next 112,720 m³	31.6762	30.9585	30.8466	29.9909	28.9074	28.0445	24.4833	22.4954	22.6284	22.2131	22.0775	13.0041
	Firm commodity charges:												
44	Customer provides compressor fuel - All volumes	0.1683	0.1313	0.1117	0.1054	0.1035	0.1051	0.1527	0.0760	0.0739	0.0720	0.0712	0.1127
	Interruptible commodity charges:												
45	Maximum - customer provides compressor fuel	7.1495	6.4795	6.3941	6.2762	6.3661	6.3905	5.5541	4.9116	4.2358	3.9841	3.8610	2.3303
46	Transportation fuel ratio - customer provides fuel	0.358%	0.351%	0.341%	0.338%	0.326%	0.323%	0.305%	0.303%	0.301%	0.251%	0.250%	0.554%
	Rate T2 (6)												
47	Monthly Charge (3)	$6,803.81	$6,500.02	$6,338.15	$6,147.68	$5,975.36	$5,440.88	$5,513.81	$5,751.12	$5,943.28	$6,013.02	$6,000.00	
	Storage ($ / GJ)												
	Monthly demand charges:												
48	Firm space	0.012	0.012	0.012	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	
	Firm Injection/Withdrawal Right												
49	Customer provides deliverability inventory	1.473	1.415	1.388	1.355	1.327	1.184	1.186	1.195	1.208	1.210	1.197	
	Commodity charges:												
50	Customer provides compressor fuel - Withdrawal	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	
51	Customer provides compressor fuel - Injection	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	
52	Storage fuel ratio - customer provides fuel	0.445%	0.430%	0.424%	0.417%	0.412%	0.408%	0.406%	0.403%	0.400%	0.397%	0.395%	
	Transportation (cents / m³)												
53	Monthly demand charge first 140,870 m³	33.1606	32.7085	32.8334	32.0677	32.0079	32.0198	26.4455	22.7402	20.9163	20.3436	20.1911	
54	Monthly demand charge all over 140,870 m³	18.4774	18.2383	18.3043	17.4997	17.3851	16.9369	13.9884	12.0285	11.0637	10.7608	10.6802	
	Firm commodity charges:												
55	Customer provides compressor fuel - All volumes	0.0420	0.0254	0.0214	0.0199	0.0200	0.0234	0.0521	0.0082	0.0080	0.0078	0.0078	
	Interruptible commodity charges:												
56	Maximum - customer provides compressor fuel	7.1623	6.4962	6.4015	6.2818	6.3701	6.3942	5.5572	4.9157	4.2400	3.9848	3.8615	
57	Transportation fuel ratio - customer provides fuel	0.309%	0.300%	0.297%	0.293%	0.291%	0.295%	0.283%	0.282%	0.279%	0.248%	0.247%	
	Rate T3												
58	Monthly Charge - City of Kitchener	$22,703.73	$21,833.55	$21,450.63	$20,996.25	$20,622.21	$19,843.96	$19,968.19	$20,208.17	$20,369.55	$20,358.77	$20,371.35	$17,549.76
	Storage ($ / GJ)												
	Monthly demand charges:												
59	Firm space	0.012	0.012	0.012	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.010
	Firm Injection/Withdrawal Right												
60	Customer provides deliverability inventory	1.473	1.415	1.388	1.355	1.327	1.184	1.186	1.195	1.208	1.210	1.197	1.012
	Commodity charges:												
61	Customer provides compressor fuel - Withdrawal	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	0.007
62	Customer provides compressor fuel - Injection	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	0.007
63	Storage fuel ratio - customer provides fuel	0.445%	0.430%	0.424%	0.417%	0.412%	0.408%	0.406%	0.403%	0.400%	0.397%	0.395%	0.597%
	Transportation (cents / m³)												
64	Monthly demand charge	20.7133	19.8760	19.5508	18.4402	17.9741	17.9898	16.7213	11.6340	10.4499	9.4605	9.3582	8.9901
	Firm commodity charges:												
65	Customer provides compressor fuel - All volumes	0.1193	0.0738	0.0526	0.0475	0.0531	0.0569	0.1339	0.0108	0.0108	0.0107	0.0107	0.0681
66	Transportation fuel ratio - customer provides fuel	0.419%	0.411%	0.404%	0.401%	0.402%	0.412%	0.380%	0.378%	0.375%	0.286%	0.285%	0.722%

Notes:
(1) Annual rates for 2019 were implemented November 1, 2019.
(2) In 2017, Cap-and-Trade charges were included in delivery charges within the approved rate schedules. The Cap-and-Trade charges have been excluded from this attachment for comparability.
(3) The monthly customer charge excludes the $1 per month charge for Bill 32.
(4) Rate M4 interruptible service was effective January 1, 2014.
(5) The current Rate M5 commodity blocking structure was effective January 1, 2014.
(6) Rate T2 was effective January 1, 2013.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[Ex.8-2-8, Attach 1 & 2] Please explain the difference between the delivery revenue included in Attachment 1, p.2, Column (a), and the ‘total delivery’ revenue for each rate class included in Attachment 2, Column (b).

Response:

The delivery revenue provided at Exhibit 8, Tab 2, Schedule 8, Attachment 1, page 2, column (a) is used to derive the delivery deficiency, which is provided at Exhibit 6. In the context of this attachment, the term “delivery” is used to indicate revenue and costs that are not “gas supply” related revenue and costs. Enbridge Gas has provided the delivery and gas supply components of the 2024 Test Year deficiency in accordance with the Filing Requirements For Natural Gas Rate Applications (Filing Requirements)[1]. The delivery deficiency excludes the following gas supply cost components:

1. gas supply commodity costs;
2. upstream transportation and fuel costs;
3. load balancing and peaking services costs;
4. market-based storage costs;
5. company use gas costs;
6. unaccounted for gas (UFG) costs; and,
7. compressor fuel costs.

The total delivery revenue for each rate class provided at Exhibit 8, Tab 2, Schedule 8, Attachment 2, column (b) includes the revenue recovered in delivery rates for each rate class. In the context of this attachment, the term “delivery” relates to the specific type of unit rate charges (monthly customer charges, delivery demand charges and/or delivery commodity charges). The amount of revenue recovered in delivery rates is based on the current approved and/or proposed rate design for each class.

Enbridge Gas has provided the delivery and gas supply cost components that, when combined, derive the proposed rates and revenue provided at Exhibit 8, Tab 2, Schedule 8, Attachment 2. The derivation of the delivery and gas supply cost components of the proposed 2024 rates and revenue by rate class are provided at Exhibit JT8.4, Attachment 4 and Attachment 5, respectively.

[1] OEB Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.34.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Please reconcile the following DSM amounts ($000) included the evidence:

a) $148,822 2024 DSM Budget (8-2-8, Attach 9)
b) $175,035 included in the CA Study (7-2-1, Attach 12, p.11-13, Sum of Ln 21 and 23)
c) $209,705 included in the CA Study (7-2-1, Attach 9, p.2, Sum of Ln 24 and 25).

Response:

The difference in the DSM Budget amounts are as follows:

a) Enbridge Gas filed its 2024 Test Year Forecast including the 2024 DSM Budget of $148.822 million on October 31, 2022 prior to the OEB's Decision and Order on the Application for Multi-Year Natural Gas DSM Plan[1] (DSM Plan). Exhibit 8, Tab 2, Schedule 8, Attachment 9 filed on November 30, 2022 presented the allocation of the $148.822 million DSM Budget to rate classes.
b) Enbridge Gas increased the 2024 DSM Budget by $26.232 million on March 8, 2023 to reflect the DSM Plan Decision. The updated 2024 DSM Budget of $175.054 million includes $30.707 million of administrative costs and $144.348 million of DSM program costs, as provided at Exhibit 7, Tab 2, Schedule 1, Attachment 12, column (a). Exhibit 8, Tab 2, Schedule 8, Attachment 9 updated on March 8, 2023 presents the allocation of the $175.054 million DSM Budget to rate classes.[2]
c) The 2024 DSM amount of $209.770 million provided at Exhibit 7, Tab 2, Schedule 1, Attachment 7, column (l) and Exhibit 7, Tab 2, Attachment 9, lines 24 and 25, includes an allocation of $34.651 million of indirect costs that occur through the cost allocation process. A reconciliation of the direct and indirect DSM administrative costs are provided at Exhibit I.7.1-IGUA-83.

Enbridge Gas has not updated the DSM Budget included in the 2024 Test Year Forecast for the 2024 budgetary inflation factor as part of this Application. The DSM budget as approved by the OEB as part of the DSM Plan Decision used a 2% proxy for inflation, as the actual inflation factor based on the Consumer Price Index (CPI) was not available at that time. The CPI for the 2024 DSM budget is estimated to be

[1] EB-2021-0002 Decision and Order, December 16, 2022.
[2] Exhibit 8, Tab 2, Schedule 8, Attachment 9, filed on March 8, 2023, has not been updated to reflect the uniform residential DSM unit rate proposal provided at Exhibit 8, Tab 2, Schedule 10.

approximately 6.8%, which will increase the DSM budget by approximately $8 million, to a total of approximately $183 million. Enbridge Gas will update the 2024 DSM Budget as part of the draft rate order or as part of a subsequent evidence update, as applicable.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[7.0-Staff-237] Please provide a revised version of Attachment 6 and 11 that shows Delivery Revenue only (similar to that filed in Attachment 2, p.2).

Response:

Please see Attachment 1 for the summary of the proposed delivery revenue change by rate class based on the cost allocation study for the current rate zones.

Please see Attachment 2 for the summary of the proposed delivery revenue change by rate class based on the cost allocation study for the proposed service areas.

Summary of Proposed Revenue Change by Rate Class - Current Rate Zones
Distribution Revenue

Line No.	Particulars	Current Approved Revenue ($000s)	Current Rate Zone: Revenue (Deficiency) / Sufficiency ($000s)	Proposed Revenue Requirement: Allocated Cost ($000s)	Proposed Revenue Requirement: Panhandle/ St. Clair Reallocation ($000s)	Proposed Revenue Requirement: Proposed Revenue Requirement ($000s)	Revenue After Recovery: S&T Margin ($000s)	Revenue After Recovery: Delivery Revenue Adjustments ($000s)	Revenue After Recovery: Proposed Revenue ($000s)	Revenue After Recovery: Revenue-to-Cost Ratio	Revenue After Recovery: Revenue Change (%)	One Rate Zone (1) Revenue After Recovery: Proposed Revenue ($000s)	One Rate Zone (1) Revenue After Recovery: Revenue Change (%)	Difference Revenue Change (%)
		(a)	(b) = (a - e)	(c)	(d)	(e) = (c + d)	(f)	(g)	(h) = (e + f + g)	(i) = (h / e)	(j) = (h - a) / (a)	(k)	(l)	(m) = (j - l)
	EGD Rate Zone													
1	Rate 1	1,033,105	(119,709)	1,151,923	890	1,152,814	(6,284)	-	1,146,530	0.995	11%	1,168,187	13%	(2%)
2	Rate 6	447,767	(18,896)	466,125	538	466,663	(5,608)	-	461,055	0.988	3%	470,293	5%	(2%)
3	Rate 100	2,060	409	1,649	3	1,651	(20)	-	1,632	0.988	(21%)	1,644	(20%)	(1%)
4	Rate 110	36,742	(2,531)	39,255	19	39,274	(643)	-	38,630	0.984	5%	38,089	4%	1%
5	Rate 115	6,950	1,362	5,587	0	5,587	(135)	-	5,452	0.976	(22%)	5,342	(23%)	2%
6	Rate 125	12,486	476	12,011	-	12,011	-	-	12,011	1.000	(4%)	11,290	(10%)	6%
7	Rate 135	1,461	(1,225)	2,685	1	2,686	(2)	-	2,683	0.999	84%	2,466	69%	15%
8	Rate 145	1,608	734	874	0	874	-	-	874	1.000	(46%)	723	(55%)	9%
9	Rate 170	3,220	2,066	1,153	1	1,154	-	-	1,154	1.000	(64%)	1,125	(65%)	1%
10	Rate 200	5,187	452	4,710	25	4,735	(149)	-	4,586	0.968	(12%)	4,649	(10%)	(1%)
11	Rate 300	-	-	-	-	-	-	-	-	-	-	-	0%	0%
12	Total EGD Rate Zone	1,550,586	(136,862)	1,685,971	1,477	1,687,448	(12,842)	-	1,674,607	0.992	8%	1,703,809	10%	(2%)
	Union North Rate Zone													
13	Rate 01	226,285	(66,349)	292,081	553	292,634	(1,148)	-	291,486	0.996	29%	209,686	(7%)	36%
14	Rate 10	30,601	(4,677)	35,173	104	35,278	(339)	-	34,939	0.990	14%	26,211	(14%)	29%
15	Rate 20	30,831	12,310	18,512	8	18,520	(116)	-	18,404	0.994	(40%)	14,765	(52%)	12%
16	Rate 25	4,865	41	4,823	0	4,824	-	-	4,824	1.000	(1%)	2,783	(43%)	42%
17	Rate 100	11,804	4,736	7,068	-	7,068	-	-	7,068	1.000	(40%)	5,572	(53%)	13%
18	Total Union North Rate Zone	304,386	(53,938)	357,659	666	358,324	(1,603)	-	356,721	0.996	17%	259,016	(15%)	32%
	Union South Rate Zone													
19	Rate M1	548,066	(82,045)	629,778	333	630,111	(2,043)	-	628,069	0.997	15%	684,032	25%	(10%)
20	Rate M2	92,168	(11,926)	104,279	(185)	104,094	(757)	-	103,337	0.993	12%	108,383	18%	(5%)
21	Rate M4	34,924	626	34,490	(193)	34,298	(269)	-	34,028	0.992	(3%)	33,928	(3%)	0%
22	Rate M5	2,674	1,053	1,621	(1)	1,621	(2)	-	1,618	0.999	(39%)	1,657	(38%)	(1%)
23	Rate M7	28,031	(7,845)	36,196	(321)	35,876	(399)	-	35,477	0.989	27%	35,908	28%	(2%)
24	Rate M9	1,774	(71)	1,863	(17)	1,845	(33)	-	1,813	0.982	2%	1,802	2%	1%
25	Rate T1	14,311	2,532	11,897	(118)	11,779	(137)	-	11,643	0.988	(19%)	12,170	(15%)	(4%)
26	Rate T2	79,193	(2,516)	83,202	(1,494)	81,709	(1,725)	-	79,984	0.979	1%	85,930	9%	(8%)
27	Rate T3	7,804	(975)	8,927	(148)	8,779	(171)	-	8,608	0.981	10%	9,163	17%	(7%)
28	Total Union South Rate Zone	808,945	(101,167)	912,254	(2,143)	910,112	(5,535)	-	904,577	0.994	12%	972,974	20%	(8%)
29	Total In-franchise	2,663,917	(291,967)	2,955,884	-	2,955,884	(19,980)	-	2,935,905	0.993	10%	2,935,799	10%	0%
	Ex-franchise													
30	Rate 331	169	164	5	-	5	164	-	169	35.360	0%	169	(0%)	0%
31	Rate 332	19,179	(2,571)	21,750	-	21,750	-	-	21,750	1.000	13%	21,757	13%	(0%)
32	Rate 401	3,561	3,561	-	-	-	3,561	-	3,561	-	0%	3,561	0%	0%
33	Rate M12/C1 Dawn-Parkway	104,651	4,205	100,446	-	100,446	11	-	100,456	1.000	(4%)	100,514	(4%)	(0%)
34	Rate C1	14,191	14,105	86	-	86	13,122	-	13,207	154.262	(7%)	13,218	(7%)	(0%)
35	Rate M13/GPA	381	379	2	-	2	767	-	769	408.267	102%	769	102%	(0%)
36	Rate M16	428	424	4	-	4	423	-	427	99.764	(0%)	427	(0%)	(0%)
37	Rate M17	529	76	453	-	453	25	-	478	1.056	(10%)	509	(4%)	(6%)
38	Total Ex-franchise	143,089	20,344	122,745	-	122,745	18,072	-	140,818	1.147	(2%)	140,924	(2%)	(0%)
39	Non-Utility Cross Charge	1,197	1,197	-		-	1,907		1,907			1,907		
40	Total	2,808,203	(270,426)	3,078,629	-	3,078,629	-	-	3,078,629	1.000	10%	3,078,629	10%	0%

Note:
(1) Excludes delivery revenue adjustments related to rate mitigation.

Summary of Proposed Revenue Change by Rate Class - Service Areas
Distribution Revenue

			Service Areas										One Rate Zone (1)		
				Proposed Revenue Requirement			Revenue After Recovery						Revenue After Recovery		
Line No.	Particulars	Current Approved Revenue ($000s)	Revenue (Deficiency) / Sufficiency ($000s)	Allocated Cost ($000s)	Panhandle/ St. Clair Reallocation ($000s)	Proposed Revenue Requirement ($000s)	S&T Margin ($000s)	Delivery Revenue Adjustments ($000s)	Proposed Revenue ($000s)	Revenue-to-Cost Ratio	Revenue Change (%)	Proposed Revenue ($000s)	Revenue Change (%)	Difference Revenue Change (%)
		(a)	(b) = (a - e)	(c)	(d)	(e) = (c + d)	(f)	(g)	(h) = (e + f + g)	(i) = (h / e)	(j) = (h - a) / (a)	(k)	(l)	(m) = (j - l)
	North Service Area													
1	Rate 01	156,291	15,253	140,707	332	141,039	(664)	-	140,375	0.995	(10%)	144,551	(8%)	(3%)
2	Rate 10	18,966	3,008	15,906	51	15,957	(196)	-	15,761	0.988	(17%)	16,345	(14%)	(3%)
3	Rate 20	13,549	6,802	6,742	5	6,747	(69)	-	6,678	0.990	(51%)	6,885	(49%)	(2%)
4	Rate 25	3,784	2,071	1,711	3	1,714	-	-	1,714	1.000	(55%)	2,159	(43%)	(12%)
5	Rate 100	8,748	4,677	4,070	-	4,070	-	-	4,070	1.000	(53%)	4,072	(53%)	(0%)
6	Total North Service Area	201,337	31,811	169,136	391	169,527	(929)	-	168,597	0.995	(16%)	174,013	(14%)	(3%)
	East Service Area													
7	Rate 1	169,721	(16,148)	185,742	127	185,869	(706)	-	185,163	0.996	9%	192,131	13%	(4%)
8	Rate 6	56,840	1,713	55,065	62	55,127	(501)	-	54,626	0.991	(4%)	59,740	5%	(9%)
9	Rate 100	639	146	492	2	493	(6)	-	487	0.988	(24%)	503	(21%)	(2%)
10	Rate 110	5,608	461	5,142	5	5,147	(74)	-	5,073	0.986	(10%)	5,821	4%	(13%)
11	Rate 115	-	-	-	-	-	-	-	-	-	-	-	-	0%
12	Rate 125	-	-	-	-	-	-	-	-	-	-	-	-	0%
13	Rate 135	223	(131)	354	0	354	(0)	-	354	1.000	59%	374	68%	(9%)
14	Rate 145	203	133	69	-	69	-	-	69	1.000	(66%)	68	(67%)	1%
15	Rate 170	622	458	164	-	164	-	-	164	1.000	(74%)	216	(65%)	(8%)
16	Rate 200	5,187	1,658	3,505	24	3,529	(107)	-	3,422	0.970	(34%)	4,649	(10%)	(24%)
17	Rate 300	-	-	-	-	-	-	-	-	-	-	-	-	0%
18	Rate 01	69,994	6,540	63,409	45	63,453	(274)	-	63,179	0.996	(10%)	65,135	(7%)	(3%)
19	Rate 10	11,636	2,969	8,656	10	8,666	(81)	-	8,585	0.991	(26%)	9,865	(15%)	(11%)
20	Rate 20	17,282	9,701	7,580	1	7,581	(27)	-	7,553	0.996	(56%)	7,879	(54%)	(2%)
21	Rate 25	1,081	18	1,063	0	1,063	-	-	1,063	1.000	(2%)	624	(42%)	41%
22	Rate 100	3,057	1,559	1,498	-	1,498	-	-	1,498	1.000	(51%)	1,499	(51%)	(0%)
23	Total East Service Area	342,091	9,077	332,739	275	333,014	(1,776)	-	331,238	0.995	(3%)	348,507	2%	(5%)
	Central Service Area													
24	Rate 1	863,384	(122,462)	984,949	897	985,846	(5,709)	-	980,137	0.994	14%	976,056	13%	0%
25	Rate 6	390,928	(29,200)	419,567	561	420,128	(5,290)	-	414,839	0.987	6%	410,553	5%	1%
26	Rate 100	1,421	311	1,110	1	1,111	(12)	-	1,099	0.989	(23%)	1,141	(20%)	(3%)
27	Rate 110	31,134	(2,205)	33,324	16	33,340	(582)	-	32,758	0.983	5%	32,269	4%	2%
28	Rate 115	6,950	1,276	5,674	0	5,674	(146)	-	5,528	0.974	(20%)	5,342	(23%)	3%
29	Rate 125	12,486	1,199	11,287	-	11,287	-	-	11,287	1.000	(10%)	11,290	(10%)	(0%)
30	Rate 135	1,238	(874)	2,111	1	2,112	(2)	-	2,110	0.999	70%	2,092	69%	1%
31	Rate 145	1,405	751	653	0	653	-	-	653	1.000	(53%)	655	(53%)	(0%)
32	Rate 170	2,598	1,612	986	1	987	-	-	987	1.000	(62%)	909	(65%)	3%
33	Rate 200	-	-	-	-	-	-	-	-	-	-	-	-	0%
34	Rate 300	-	-	-	-	-	-	-	-	-	-	-	-	0%
35	Total Central Service Area	1,311,544	(149,594)	1,459,661	1,477	1,461,138	(11,741)	-	1,449,397	0.992	11%	1,440,305	10%	1%
	South Service Area													
36	Rate M1	548,066	(146,116)	693,849	333	694,182	(2,043)	-	692,139	0.997	26%	684,032	25%	1%
37	Rate M2	92,168	(19,842)	112,194	(185)	112,010	(757)	-	111,253	0.993	21%	108,383	18%	3%
38	Rate M4	34,924	(210)	35,327	(193)	35,134	(269)	-	34,865	0.992	(0%)	33,928	(3%)	3%
39	Rate M5	2,674	921	1,753	(1)	1,752	(2)	-	1,750	0.999	(35%)	1,657	(38%)	3%
40	Rate M7	28,031	(9,734)	38,086	(321)	37,765	(399)	-	37,367	0.989	33%	35,908	28%	5%
41	Rate M9	1,774	(187)	1,979	(17)	1,962	(33)	-	1,929	0.983	9%	1,802	2%	7%
42	Rate T1	14,311	1,997	12,433	(118)	12,315	(137)	-	12,178	0.989	(15%)	12,170	(15%)	0%
43	Rate T2	79,193	(8,512)	89,199	(1,494)	87,705	(1,725)	-	85,980	0.980	9%	85,930	9%	0%
44	Rate T3	7,804	(1,547)	9,499	(148)	9,351	(171)	-	9,179	0.982	18%	9,163	17%	0%
45	Total South Service Area	808,945	(183,230)	994,318	(2,143)	992,175	(5,536)	-	986,640	0.994	22%	972,974	20%	2%
46	Total In-franchise	2,663,917	(291,937)	2,955,854	-	2,955,854	(19,982)	-	2,935,871	0.993	10%	2,935,799	10%	0%
	Ex-franchise													
47	Rate 331	169	164	5	-	5	164	-	169	35.360	0%	169	0%	0%
48	Rate 332	19,179	(2,571)	21,750	-	21,750	-	-	21,750	1.000	13%	21,757	13%	(0%)
49	Rate 401	3,561	3,561	-	-	-	3,561	-	3,561	-	0%	3,561	0%	0%
50	Rate M12/C1 Dawn-Parkway	104,651	4,205	100,446	-	100,446	11	-	100,456	1.000	(4%)	100,514	(4%)	(0%)
51	Rate C1	14,191	14,105	86	-	86	13,122	-	13,207	154.262	(7%)	13,218	(7%)	(0%)
52	Rate M13/GPA	381	379	2	-	2	767	-	769	408.267	102%	769	102%	(0%)
53	Rate M16	428	424	4	-	4	423	-	427	99.764	(0%)	427	(0%)	(0%)
54	Rate M17	529	46	483	-	483	25	-	508	1.052	(4%)	509	(4%)	(0%)
55	Total Ex-franchise	143,089	20,314	122,775	-	122,775	18,072	-	140,848	1.147	(2%)	140,924	(2%)	(0%)
56	Non-Utility Cross Charge	1,197	1,197	-	-	-	1,910	-	1,910			1,907		
57	Total	2,808,203	(270,426)	3,078,629	-	3,078,629	-	-	3,078,629	1.000	10%	3,078,629	10%	0%

Note:
(1) Excludes delivery revenue adjustments related to rate mitigation.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[7.0-Staff-237] Enbridge notes that if the OEB approves an alternative rate zone scenario, Enbridge will require additional time to develop a rate design proposal and to implement the changes. It further states that: "Given the additional time required to implement a rate zone alternative, Enbridge Gas would propose to maintain the current rate zones and rate classes for cost allocation and rate design until such time as the rate design proposal is approved and system changes were complete." In a scenario where a rate zone alternative is approved, please clarify Enbridge's expectations/proposal for the cost allocation and rate design process for an approved 2024 revenue requirement.

Response:

Should the OEB approve a rate zone alternative as part of this Application, Enbridge Gas would require additional time for implementation. In the interim period prior to implementation of the approved rate zone alternative, Enbridge Gas would propose to maintain the current rate zones and rate classes for cost allocation and rate design. Enbridge Gas would derive the 2024 rates using the 2024 Cost Allocation Study prepared for the current rate zones, as provided at Exhibit 7.0-Staff-237, Attachment 4, and current approved rate design methodologies. From a gas cost perspective, Enbridge Gas would continue to use the current approved rate design for the gas supply commodity, transportation and load balancing rates for each rate zone, where applicable. Enbridge Gas would maintain the current gas cost deferral accounts, until such time as the rate zone alternative rate design and updated gas cost deferral accounts could be implemented.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[7.0-Staff-237] Please confirm that the Cost Allocation Study included in Attachment 1 is Enbridge's most up-to-date Cost Allocation proposal.

Response:

Confirmed. Exhibit 7.0-Staff-237, Attachment 1 is the most up-to-date Cost Allocation Study prepared based on one rate zone.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

[JT 4.21] With respect to Table 3:

a) Please confirm that 'Total OH in Base Capital' reflects the total amount of capitalized overheads recovered in rates in each year through base rates and ICM/capital pass-through mechanisms.
b) Please explain how Enbridge calculated the EGD and UG Non-ICM/CPT OH amounts recovered in rates.

Response:

a) Confirmed. The amounts reflect overheads recovered in base rates and through ICM and CPT mechanisms but do not reflect adjustments captured in the APCDA relative to the new overhead capitalization policy. Please see JT 4.21 Table 4 for the calculated APCDA adjustments.

b) On an annual basis, indirect overheads are allocated to projects based on the percentage of total indirect overheads over total direct capital in the year of expense. This includes allocations to ICM, Integration and all other projects identified in the AMP. The EGD and UG Non-ICM/CPT OH amounts represent the overheads allocated to projects included in the AMP and excludes overhead assigned to both Integration and ICM/CPT capital. Please see the Table 1 below for an illustrative example of how the overhead allocation is derived based on 2022 actuals:

Table 1
2022 Actual Overhead Allocation ($ millions)

Total Capital Expenditures	1,437.1
Less	
Community Expansion	14.2
EA Fixed Overheads	27.0
Other	1.1
Sub total	1,394.7
Capitalized Overheads	285.6
Net Direct Capital	1,109.1
Overhead Allocation Rate	25.7%

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

With reference to Exhibit I.2.4-PP-29, which in turn refers to Ex2/T4/S2/T3, could you please explain how EGI derived the $15.4 million reduction in capitalized overhead and concomitant $15.4 million increase in OM&A for 2024?

Would this approach be replicable in future years (post-2024), and if not please explain why not.

Response:

For clarification the Enbridge Gas proposal results in a $15.4 million dollar increase in capitalized overheads and a $15.4 million decrease in O&M for the 2024 Test Year.

Please refer to paragraph 37 in Exhibit 2, Tab 4, Schedule 2 for details on how the values in Table 3 were derived. In summary, the rates in column (b) of Table 3 represent the capitalization rates calculated under EGD's and Union's historical methodologies based on data from the 2020 budget. The rates in column (d) represent overhead capitalization rates under the harmonized methodology, which is described In Section 3 of Exhibit 2, Tab 4, Schedule 2. Columns (a) and (c) were calculated by applying the rates in columns (b) and (d), respectively, to eligible costs in the 2024 Test Year Forecast.

Enbridge Gas could replicate the analysis described above for years post-2024 pending completion of each year's budget process and annual capitalization rate studies. However, the capitalization rates used to quantify the impact of the old methodologies would still be based on the 2020 budget data. Due to organizational changes, harmonization of processes and changes in accounting records and systems that have occurred since 2020, it is not possible to calculate updated capitalization rates for the old methodologies. As a result, replicating the analysis in Table 3 for years post-2024 would become less relevant and less meaningful over time, as business functions and costs eligible for capitalization change from what they were in 2020.

Enbridge Gas provided, on a best efforts basis, high-level estimates of the variances that could occur in 2025 and 2026 in the response to Exhibit I.2.4-PP-29. Consistent with how the 2025 and 2026 O&M forecasts were developed, the estimated 2025 and 2026 impacts in Exhibit I.2.4-PP-29 were derived by escalating the 2024 impact by O&M LRP assumptions. The variance between the old and harmonized methodologies could fluctuate significantly and/or change directionally year over year due to changes in departmental level spend, new business program adds, changes in capitalization rates based on annual rate studies, and future organizational changes.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Reference to Exhibit I.ADR.10

In 2013 cost of service, Union stated contingency space was needed for economical pricing. Exhibit I.ADR.10 response indicates it is needed for economical considerations, system operator, etc. Please elaborate on the need for operational contingency and what services are supported by keeping the space empty. Why does Enbridge Gas need it and are those operational contingency purposes utility or non-utility? Where is the contingency space held (i.e. which pool(s))?

Response:

As explained in Exhibit I.4.2-FRPO-131 operational contingency includes 4.8 PJ of empty space used to manage late season injections. The 4.8 PJ is allocated among 3 components as follows:

- Weather 2.9 PJ
- Reservoir Factors 1.3 PJ
- OBA 0.7 PJ

Weather

Weather can vary significantly from average as shown in Exhibit I.4.2-FRPO-134, Table 1 at the end of the injection season. As the storage system is approaching full the empty space is used to manage these variances in weather and provides space to cover injections when the weather is warmer than average. This only provides benefit to the utility customers since their demand is heat sensitive.

Non-utility customer injections are managed through contract parameters. LST customers do not have any firm injection rights between October 1 and November 30. LTP customers do not have any firm injection rights at any time.

Storage Pool Factors

The two components of reservoir factors that make up the 1.3 PJ are storage pool variances and storage pool hysteresis. Storage pool variances, which make up approximately 85% of the 1.3 PJ, account for differences between calculated inventories based on pressure and measured inventories based on storage pool measurement. Storage pools are shut-in at the end of the injection season based on the pressure at the observation well. Inventory balances based on measured volumes may show that additional space was available. Operational contingency can be used to mitigate the impact of the loss in anticipated space at the end of the injection season.

Utility and non-utility customers benefit from this component. The operational contingency costs for this component are allocated to the non-utility customers in proportion to the non-utility storage use of operational contingency space, consistent with the cost allocation methodology for the 2024 Cost Allocation Study, provided at Exhibit 7, Tab 1, Schedule 2, based on the proportion of storage space used by each group.

OBA

OBA imbalances occur at pipeline interconnects on the EGI system. These imbalances can lead to additional injections into storage throughout the season. This is particularly important at the end of the injection season. Operational contingency is used to manage the OBA imbalances on a daily basis.

Utility and non-utility customers benefit from this component.

Allocation of costs to Non-utility Operations

The operational contingency costs for storage pool factors and OBA also support the non-utility storage business operations. The storage space and molecules for operational contingency are not colour-coded to identify the use; therefore, Enbridge Gas has used allocation methodologies to allocate costs between the utility and non-utility operations for these components. Operational contingency costs are allocated to the non-utility operations through the non-utility cross charge. The costs are allocated between utility and non-utility operations in proportion to the use of operational contingency space for storage pool factors and OBA, consistent with the cost allocation methodology for the 2024 Cost Allocation Study. The allocation of operational contingency components between utility and non-utility operations is provided at Exhibit I.4.2-FRPO-141. The methodologies used to allocate operational contingency components between utility and non-utility operations is provided at Exhibit I.7.1-IGUA-76.

Historical Usage

Table 1 of Exhibit I.4.2-FRPO-132 Table 1 shows the historical usage of the operational contingency empty space varied between 1.9 PJ and 7.7 PJ for the years 2017 through to 2021.

Pools holding the Operational Contingency Space

The operational contingency space at the end of the injection season is held in 59-85, 156 and Dow Moore.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Please provide the foreign exchange rates that Enbridge Gas would use from Bank of Canada to complete the provided table from Exhibit I.ADR.11.

Response:

Please see the table below for the daily foreign exchange rate per the Bank of Canada on the trade date indicated.[1]

Line No.	Date	Bank of Canada Daily FX Rates
2018/2019		
1	Feb. 1/18	1.229
2	Nov. 1/17	1.288
3	May. 1/17	1.366
4	Nov. 1/16	1.338
2019/2020		
5	Feb. 1/19	1.31
6	Nov. 1/18	1.309
7	May. 1/18	1.287
8	Nov. 1/17	1.288
2020/21		
9	Feb. 1/20	1.323
10	Nov. 1/19	1.316
11	May. 1/19	1.342
12	Nov. 1/18	1.309
2021/2022		
13	Feb. 1/21	1.282
14	Nov. 1/20	1.332
15	May. 1/20	1.407
16	Nov. 1/19	1.316
2022/2023		
17	Feb. 1/22	1.269
18	Nov. 1/21	1.237
19	May. 1/21	1.228
20	Nov. 1/20	1.332

[1] Bank of Canada. Daily exchange rates. https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates/

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Reference to Exhibit I.ADR.11

Enbridge Gas is deferring the purchase of 10 PJ of incremental storage and is presumably purchasing Dawn supply in its place until resolution in Phase 2. Why can't Enbridge Gas purchase an additional 10 PJ of Dawn supply instead of purchasing storage at market-based rates?

Response:

Enbridge Gas plans to maintain its current portfolio of 26.1 PJ of market-based storage until an OEB Decision on Phase 2 is received. Following an OEB Decision on Phase 2, Enbridge Gas will make adjustments to its Gas Supply Plan, including its storage portfolio, as soon as is practical.

For example, if the OEB approves Enbridge Gas's proposal in the first quarter of 2024, Enbridge Gas anticipates it would make necessary contracting changes to add 1.9 PJ to its storage portfolio in advance of winter 2024/2025, as Enbridge Gas would have sufficient time to execute the blind RFP process in advance of that winter.[1] If the OEB approves Enbridge Gas's proposal after the first quarter of 2024, Enbridge Gas would make the necessary contracting changes as early as practically possible (taking into account the time required to execute the blind RFP process). If Enbridge Gas's storage proposal is not approved and Enbridge Gas is required to reduce the amount of market-based storage in its portfolio, those changes would be made as soon as the terms of existing contracts allow. Enbridge Gas will not be purchasing an additional 10 PJ of winter supply as presumed in this question.

As indicated in the ICF Report, selecting storage rather than Dawn purchases "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."[2]

Additionally, ICF highlights that purchases should not be considered a replacement for the value provided by storage:

[1] This assumes a storage contracting year of April 1 to March 31, annually.
[2] Exhibit 4, Tab 2, Schedule 1, Attachment 6, p.14.

"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 [*sic*] 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."[3]

Enbridge Gas agrees with ICF's recommendations and conclusions.

[3] Ibid, p.68.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Reference to Exhibit JT5.02

Confirm the list of 2023/2024 deferred projects does not include PREP. If confirmed, what is the new 2024 rate base if removed.

Response:

Confirmed. Attachment 1 to JT5.02 did not include PREP.

Removing the 2023/2024 in-service additions for PREP results in a further $250.8 million reduction to 2024 Rate Base (from the $16,011.8 million in the initial response dated May 26th which removed only 2023 projects cancelled/deferred as per Exhibit JT5.2 to $15,761.0 million). Again, this reduction was quantified using simplifying assumptions (outlined below) for illustrative purposes only in response to this question.

The following simplifying assumptions were made in calculating the impact noted above:

- Capital amounts are as filed in the 2023 to 2032 AMP and include the estimated in-service capital for both the 2023 Panhandle Loop and 2024 Leamington Interconnect projects.
- A monthly profile was applied to in-service additions consistent with the forecasting methodology for depreciation expense. (i.e. not a November ISD)
- Depreciation rates adjusted in 2024 to reflect new proposed rates.
- Estimated reduction includes overhead capitalization which would be re-allocated to other projects rather than cancelled/deferred.
- The calculations do not contemplate the impact of alternative proposals that EGI may bring forward related to PREP.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Reference to Exhibit I.7.0-Staff-237, Attachment 9

How is distribution revenue requirement allocated to service areas and then to the rate classes in those service areas?

Response:

The distribution function costs provided at Exhibit I.7.0-STAFF-237, Attachment 9 are allocated to rate classes based on one rate zone for purposes of the cost allocation study prepared based on service areas. The allocation of distribution function costs by rate class is the same as the proposed 2024 Cost Allocation Study filed as Exhibit I.7.0-STAFF-237, Attachment 1, which is also prepared based on one rate zone. To derive the distribution costs by service area, a common distribution unit rate based on one rate zone was applied to the billing units for each rate class.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

2023 rates in Exhibit 8, Tab 2, Schedule 8, Attachment 4, differs from Exhibit I.ADR.28 Attachment 1. Are they on a different basis? Please provide the 2024 equivalent of those amounts on the same basis as shown for 2023 and previous years.

Response:

Please see Attachment 1. Enbridge Gas has updated the response provided at Exhibit I.ADR.28, Attachment 1 to include 2023 rates and proposed 2024 rates on the same basis. Enbridge Gas has provided 2022, 2023 and 2024 proposed rates based on the April 2022 QRAM, consistent with the Application. The previous years from 2012 to 2021 are based on the actual historic rates that were effective in October of each of the respective years.

2012 to 2024 Annual Delivery Rates
EGD Rate Zone

Line No.	Particulars (cents/m^3)	2024 EB-2022-0200 (1) January 1, 2024 (a)	2023 EB-2022-0133 (2) January 1, 2023 (b)	2022 EB-2022-0089 April 1, 2022 (d)	2021 EB-2021-0219 October 1, 2021 (e)	2020 EB-2020-0195 October 1, 2020 (f)	2019 (3) EB-2018-0305 November 1, 2019 (g)	2018 EB-2018-0249 October 1, 2018 (h)	2017 EB-2017-0281 October 1, 2017 (i)	2016 EB-2016-0260 October 1, 2016 (j)	2015 EB-2015-0242 October 1, 2015 (k)	2014 EB-2014-0191 October 1, 2014 (l)	2013 EB-2013-0295 October 1, 2013 (m)	2012 EB-2012-0352 October 1, 2012 (n)
	Rate 1													
1	Monthly Customer Charge (4)	$25.19	$21.88	$21.12	$20.83	$20.48	$20.21	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
	Delivery Charge per cubic metre													
2	For the first 30 m^3 per month	12.0903	10.6256	10.0223	9.7651	9.7072	9.4710	9.5938	8.5010	8.1715	7.3025	6.7766	7.2856	7.0977
3	For the next 55 m^3 per month	11.2871	9.9456	9.3815	9.1455	9.0910	8.8718	8.9757	7.9534	7.6451	6.8320	6.3400	6.8163	6.6405
4	For the next 85 m^3 per month	10.6582	9.4131	8.8797	8.6604	8.6086	8.4026	8.4916	7.5244	7.2328	6.4636	5.9981	6.4485	6.2822
5	For all over 170 m^3 per month	10.1893	9.0162	8.5056	8.2987	8.2489	8.0528	8.1308	7.2048	6.9256	6.1890	5.7432	6.1746	6.0154
6	Gas Supply Load Balancing	Note (5)	1.2933	1.2776	1.2519	1.1398	1.2268	1.6642	1.5267	1.6558	1.1431	0.7564	0.9043	1.0951
7	Gas Supply Transportation (6)	1.9423	3.9267	3.9258	4.1543	4.0953	4.2588	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
8	Gas Supply Transportation Dawn (7)	Note (6)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
9	Gas Supply Western Transportation (6)	3.8042	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate 6													
10	Monthly Customer Charge (4)	$80.00	$76.58	$73.91	$72.89	$71.68	$70.75	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00
	Delivery Charge per cubic metre													
11	For the first 500 m^3 per month	11.8215	10.0237	9.8715	9.3466	9.0781	8.7829	8.9813	8.2106	8.0119	7.3605	7.0389	7.2760	6.9233
12	For the next 1050 m^3 per month	8.9002	7.6575	7.5279	7.1517	6.9515	6.7327	6.8659	6.2767	6.1249	5.6269	5.3809	5.5622	5.2925
13	For the next 4500 m^3 per month	6.8545	6.0005	5.8866	5.6147	5.4623	5.2970	5.3846	4.9225	4.8035	4.4129	4.2200	4.3623	4.1508
14	For the next 7000 m^3 per month	5.5402	4.9360	4.8322	4.6272	4.5056	4.3746	4.4329	4.0524	3.9544	3.6328	3.4740	3.5910	3.4170
15	For the next 15250 m^3 per month	4.9562	4.4629	4.3637	4.1884	4.0804	3.9647	4.0100	3.6659	3.5772	3.2863	3.1426	3.2486	3.0910
16	For all over 28300 m^3 per month	4.8095	4.3441	4.2460	4.0782	3.9737	3.8617	3.9038	3.5687	3.4824	3.1993	3.0595	3.1626	3.0093
17	Gas Supply Load Balancing	Note (5)	1.2062	1.1915	1.1669	1.0630	1.1416	1.5422	1.4066	1.5439	1.0532	0.6311	0.7476	0.9148
18	Gas Supply Transportation (6)	1.8435	3.9267	3.9258	4.1543	4.0953	4.2588	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
19	Gas Supply Transportation Dawn (7)	Note (6)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
20	Gas Supply Western Transportation (6)	3.7054	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate 9													
21	Monthly Customer Charge (4)	Note (8)	$258.11	$249.15	$245.71	$241.60	$238.47	$235.95	$235.95	$235.95	$235.95	$235.95	$235.95	$235.95
	Delivery Charge per cubic metre													
22	For the first 20,000 m^3 per month	Note (8)	12.3212	11.8936	11.7249	11.5228	11.3720	11.2489	10.9204	10.6625	10.5854	10.3615	10.7735	10.7426
23	For all over 20,000 m^3 per month	Note (8)	11.5339	11.1336	10.9755	10.7859	10.6446	10.5292	10.2218	9.9804	9.9081	9.6986	10.0844	10.0553
24	Gas Supply Load Balancing	Note (8)	0.0168	0.0161	0.0155	0.0139	0.0147	0.0196	0.0179	0.0185	0.0136	0.0170	0.0000	0.0053
25	Gas Supply Transportation	Note (8)	3.9267	3.9258	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
26	Gas Supply Transportation Dawn (7)	Note (8)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
	Rate 100													
27	Monthly Customer Charge (4)	$500.00	$133.47	$128.83	$127.05	$124.93	$123.32	$122.01	$122.01	$122.01	$122.01	$122.01	$122.01	$122.01
	Delivery Charge													
28	Per cubic metre of Contract Demand	43.3831	39.6129	38.1135	37.5887	36.9620	36.3852	36.0000	36.0000	36.0000	36.0000	36.0000	8.1900	8.1900
	Per cubic metre of gas delivered													
29	For the first 14,000 m^3 per month	0.3892	0.1875	0.1875	0.1829	0.1766	0.1747	0.1771	0.1729	0.1547	0.1576	0.1729	5.0951	5.0132
30	For the next 28,000 m^3 per month	0.3892	0.1875	0.1875	0.1829	0.1766	0.1747	0.1771	0.1729	0.1547	0.1576	0.1729	3.7361	3.6542
31	For all over 42,000 m^3 per month	0.3892	0.1875	0.1875	0.1829	0.1766	0.1747	0.1771	0.1729	0.1547	0.1576	0.1729	3.1771	3.0952
32	Gas Supply Load Balancing	Note (5)	1.2037	1.1915	1.1669	1.0630	1.1416	1.5422	1.4066	1.5439	1.0532	0.6311	0.4948	0.5960
33	Gas Supply Transportation (6)	1.3356	3.9267	3.9258	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
34	Gas Supply Transportation Dawn (7)	Note (6)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
35	Gas Supply Western Transportation (6)	3.1976	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate 110													
36	Monthly Customer Charge (4)	$500.00	$642.55	$620.22	$611.66	$601.43	$593.65	$587.37	$587.37	$587.37	$587.37	$587.37	$587.37	$587.37
	Delivery Charge													
37	Per cubic metre of Contract Demand	47.5826	25.3940	24.3206	23.9866	23.5878	23.1551	22.9100	22.9100	22.9100	22.9100	22.9100	22.9100	22.9100
	Per cubic metre of gas delivered													
38	For the first 1,000,000 m^3 per month	0.3537	1.0326	0.9851	0.9053	0.8538	0.8333	0.8549	0.7449	0.7240	0.5693	0.5584	0.5834	0.5201
39	For all over 1,000,000 m^3 per month	0.3537	0.8646	0.8238	0.7467	0.6985	0.6808	0.7049	0.5949	0.5740	0.4193	0.4084	0.4334	0.3701
40	Gas Supply Load Balancing	Note (5)	0.2523	0.2490	0.2425	0.2179	0.2344	0.3237	0.2974	0.3039	0.2056	0.0945	0.1552	0.1651
41	Gas Supply Transportation (6)	1.2011	3.9267	3.9258	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
42	Gas Supply Transportation Dawn (7)	Note (6)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
43	Gas Supply Western Transportation (6)	3.0630	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

2012 to 2024 Annual Delivery Rates
EGD Rate Zone

Line No.	Particulars (cents/m³)	2024 EB-2022-0200 (1) January 1, 2024	2023 EB-2022-0133 (2) January 1, 2023	2022 EB-2022-0089 April 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (3) EB-2018-0305 November 1, 2019	2018 EB-2018-0249 October 1, 2018	2017 EB-2017-0281 October 1, 2017	2016 EB-2016-0260 October 1, 2016	2015 EB-2015-0242 October 1, 2015	2014 EB-2014-0191 October 1, 2014	2013 EB-2013-0295 October 1, 2013	2012 EB-2012-0352 October 1, 2012
		(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Rate 115													
44	Monthly Customer Charge (4)	$500.00	$681.11	$657.44	$648.36	$637.53	$629.28	$622.62	$622.62	$622.62	$622.62	$622.62	$622.62	$622.62
	Delivery Charge													
45	Per cubic metre of Contract Demand	36.9948	27.1243	25.8942	25.5390	25.1149	24.6207	24.3600	24.3600	24.3600	24.3600	24.3600	24.3600	24.3600
	Per cubic metre of gas delivered													
46	For the first 1,000,000 m³ per month	0.2848	0.6708	0.6581	0.5200	0.4782	0.4414	0.4325	0.3733	0.3663	0.2181	0.2069	0.2104	0.1956
47	For all over 1,000,000 m³ per month	0.2848	0.5683	0.5563	0.4188	0.3774	0.3409	0.3325	0.2733	0.2663	0.1181	0.1069	0.1104	0.0956
48	Gas Supply Load Balancing	Note (5)	0.0948	0.0937	0.0918	0.0847	0.0897	0.1159	0.1071	0.1093	0.0814	0.0449	0.0487	0.0568
49	Gas Supply Transportation (6)	0.9199	3.9267	3.9258	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
50	Gas Supply Transportation Dawn (7)	Note (6)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
51	Gas Supply Western Transportation (6)	2.7818	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate 125													
52	Monthly Customer Charge (4)	$3,000.00	$546.97	$527.96	$520.67	$511.97	$505.35	$500.00	$500.00	$500.00	$500.00	$500.00	$500.00	$500.00
	Delivery Charge													
53	Per cubic metre of Contract Demand	10.4612	11.2127	10.7838	10.6389	10.4657	10.1505	9.8840	9.7583	9.0962	8.2361	8.0942	9.0982	9.1119
	Rate 135													
54	Monthly Customer Charge (4)	$500.00	$125.89	$121.52	$119.84	$117.84	$116.31	$115.08	$115.08	$115.08	$115.08	$115.08	$115.08	$115.08
	Delivery Charge per cubic metre of gas delivered													
	December to March													
55	For the first 14,000 m³ per month	11.2873	8.7072	8.1249	7.8043	7.5200	7.3244	7.1599	7.0979	7.0941	6.7146	6.6924	6.7006	6.6899
56	For the next 28,000 m³ per month	9.5053	7.2308	6.7649	6.4921	6.2574	6.0949	5.9599	5.8979	5.8941	5.5146	5.4924	5.5006	5.4899
57	For all over 42,000 m³ per month	8.7993	6.6456	6.2636	6.0259	5.8256	5.6848	5.5599	5.4979	5.4941	5.1146	5.0924	5.1006	5.0899
	April to November													
58	For the first 14,000 m³ per month	4.4226	3.0187	2.8133	2.6470	2.5264	2.4429	2.4599	2.3979	2.3941	2.0146	1.9924	2.0006	1.9899
59	For the next 28,000 m³ per month	3.4147	2.1834	2.0374	1.8954	1.8004	1.7343	1.7599	1.6979	1.6941	1.3146	1.2924	1.3006	1.2899
60	For all over 42,000 m³ per month	3.1060	1.9276	1.8069	1.6755	1.5911	1.5319	1.5599	1.4979	1.4941	1.1146	1.0924	1.1006	1.0899
61	Gas Supply Load Balancing	Note (5)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
62	Gas Supply Transportation (6)	0.8875	3.9267	3.9258	4.1543	4.0953	4.2588	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
63	Gas Supply Transportation Dawn (7)	Note (6)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
64	Gas Supply Western Transportation (6)	2.7495	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate 145													
65	Monthly Customer Charge (4)	$134.93	$134.93	$130.24	$128.44	$126.29	$124.66	$123.34	$123.34	$123.34	$123.34	$123.34	$123.34	$123.34
	Delivery Charge													
66	Per cubic metre of Contract Demand	11.4308	9.0517	8.7168	8.5968	8.4535	8.3181	8.2300	8.2300	8.2300	8.2300	8.2300	8.2300	8.2300
	Per cubic metre of gas delivered													
67	For the first 14,000 m³ per month	0.8171	7.4823	6.3919	5.4334	3.6210	3.0957	3.0046	2.9780	2.9419	2.6374	2.7809	2.8008	2.7387
68	For the next 28,000 m³ per month	0.8171	6.1081	5.0178	4.0592	2.2473	1.7248	1.6456	1.6190	1.5829	1.2784	1.4219	1.4418	1.3797
69	For all over 42,000 m³ per month	0.8171	5.5426	4.4524	3.4938	1.6821	1.1607	1.0866	1.0600	1.0239	0.7194	0.8629	0.8828	0.8207
70	Gas Supply Load Balancing	Note (5)	0.5673	0.5599	0.5459	0.4933	0.5283	0.7187	0.6259	0.6618	0.4859	0.1739	0.1853	0.1870
71	Gas Supply Transportation (6)	0.8875	3.9267	3.9258	4.1543	4.0953	4.2588	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
72	Gas Supply Transportation Dawn (7)	Note (6)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
73	Gas Supply Western Transportation (6)	2.7495	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate 170													
74	Monthly Customer Charge (4)	$305.55	$305.55	$294.93	$290.86	$286.00	$282.30	$279.31	$279.31	$279.31	$279.31	$279.31	$279.31	$279.31
	Delivery Charge													
75	Per cubic metre of Contract Demand	3.7447	4.4945	4.3269	4.2673	4.1961	4.1338	4.0900	4.0900	4.0900	4.0900	4.0900	4.0900	4.0900
	Per cubic metre of gas delivered													
76	For the first 1,000,000 m³ per month	1.4682	0.5980	0.7693	0.6128	0.5626	0.4068	0.5530	0.5101	0.5064	0.3968	0.4912	0.4858	0.4756
77	For all over 1,000,000 m³ per month	1.4682	0.3940	0.5657	0.4094	0.3595	0.2051	0.3530	0.3101	0.3064	0.1968	0.2912	0.2858	0.2756
78	Gas Supply Load Balancing	Note (5)	0.2465	0.2432	0.2370	0.2135	0.2291	0.3145	0.2897	0.3159	0.2592	0.0965	0.1034	0.1061
79	Gas Supply Transportation (6)	0.8875	3.9267	3.9258	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
80	Gas Supply Transportation Dawn (7)	Note (6)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
81	Gas Supply Western Transportation (6)	2.7495	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

2012 to 2024 Annual Delivery Rates
EGD Rate Zone

Line No.	Particulars (cents/m³)	2024 EB-2022-0200 (1) January 1, 2024	2023 EB-2022-0133 (2) January 1, 2023	2022 EB-2022-0089 April 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (3) EB-2018-0305 November 1, 2019	2018 EB-2018-0249 October 1, 2018	2017 EB-2017-0281 October 1, 2017	2016 EB-2016-0260 October 1, 2016	2015 EB-2015-0242 October 1, 2015	2014 EB-2014-0191 October 1, 2014	2013 EB-2013-0295 October 1, 2013	2012 EB-2012-0352 October 1, 2012
		(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Rate 200													
82	Monthly Customer Charge - Maximum	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00
	Delivery Charge													
83	Per cubic metre of Firm Contract Demand	30.2926	16.2592	15.7004	15.4861	15.2302	14.8573	14.7000	14.7000	14.7000	14.7000	14.7000	14.7000	14.7000
84	Per cubic metre of gas delivered	0.5483	1.3602	1.3589	1.3080	1.2033	1.1839	1.2394	1.1327	1.0976	1.1953	1.2818	1.2815	1.1941
85	Gas Supply Load Balancing	Note (5)	1.1360	1.1218	1.0960	0.9933	1.0668	1.4523	1.2546	1.3345	0.8634	0.4253	0.5507	0.6784
86	Gas Supply Transportation (6)	1.4137	3.9267	3.9258	4.1543	4.0953	4.2589	4.9407	5.3414	5.6356	6.3318	5.0013	4.6443	5.4600
87	Gas Supply Transportation Dawn (7)	Note (6)	0.9697	0.9694	0.9703	0.8174	0.8192	1.0404	1.1404	N/A	N/A	N/A	N/A	N/A
88	Gas Supply Western Transportation (6)	3.2757	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Notes:
(1) 2024 Rates as proposed, updated May 18, 2023.
(2) 2023 Rates at April 2022 QRAM (EB-2022-0133) per Exhibit 8, Tab 2, Schedule 8, Attachment 2.
(3) Annual rates for 2019 were implemented November 1, 2019.
(4) The monthly customer charge excludes the $1 per month charge for Bill 32.
(5) Enbridge Gas has proposed to include the cost of load balancing in transportation charges effective 2024.
(6) For 2023 and earlier, the gas supply transportation rate was applicable to sales service and Empress bundled direct purchase customers and the gas supply transportation Dawn rate was applicable to Dawn bundled direct purchase customers.
For 2024, the gas supply transportation rate is proposed to be applicable to sales service and Dawn bundled direct purchase customers and the gas supply transportation Western rate is proposed to be applicable to Empress bundled direct purchase customers.
(7) The gas supply transportation Dawn service was implemented in 2017.
(8) Rate 9 is proposed for elimination in 2024.

2012 to 2024 Annual Delivery Rates
Union North Rate Zone

Line No.	Particulars (cents/m³)	2024 EB-2022-0200 (1) January 1, 2024 (a)	2023 EB-2022-0133 (2) January 1, 2023 (b)	2022 EB-2022-0089 April 1, 2022 (d)	2021 EB-2021-0219 October 1, 2021 (e)	2020 EB-2020-0195 October 1, 2020 (f)	2019 (3) EB-2018-0305 November 1, 2019 (g)	2018 EB-2018-0253 October 1, 2018 (h)	2017 (4) EB-2017-0278 October 1, 2017 (i)	2016 EB-2016-0247 October 1, 2016 (j)	2015 EB-2015-0255 October 1, 2015 (k)	2014 EB-2014-0208 October 1, 2014 (l)	2013 EB-2013-0316 October 1, 2013 (m)	2012 EB-2012-0345 October 1, 2012 (n)
	Rate 01													
1	Monthly Charge - All Zones (5)	$25.19	$22.98	$22.18	$21.87	$21.50	$21.22	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00
	Monthly Delivery Charge - All Zones													
2	First 100 m³	7.7601	11.1409	10.2933	9.9079	9.5316	9.4044	9.3755	9.1537	8.9080	9.0309	9.1540	9.6435	7.5251
3	Next 200 m³	7.5738	10.8629	10.0361	9.6573	9.2870	9.1622	9.1356	8.9207	8.6825	8.8028	8.8074	9.1190	7.0146
4	Next 200 m³	7.2786	10.4222	9.6286	9.2604	8.8999	8.7792	8.7563	8.5530	8.3287	8.4451	8.4507	8.7463	6.6519
5	Next 500 m³	7.0078	10.0179	9.2547	8.8962	8.5446	8.4275	8.4081	8.2155	8.0040	8.1168	8.1233	8.4043	6.3191
6	Over 1,000 m³	6.7839	9.6836	8.9456	8.5952	8.2510	8.1369	8.1204	7.9367	7.7358	7.8457	7.8529	8.1218	6.0442
	Gas Supply Transportation Service (6)													
7	Union North West Zone (previously Fort Frances)	3.3217	4.4904	4.4899	4.6613	5.4837	5.4855	6.6802	6.8585	5.8185	5.7686	4.1399	4.3403	5.8897
8	Union North West Zone (previously Western Zone)	3.3217	4.4904	4.4899	4.6613	5.4837	5.4855	6.6802	6.8585	4.9868	4.9541	4.0901	4.2882	6.2981
9	Union North East Zone (previously Northern Zone)	3.3217	2.2975	2.2890	2.3084	2.0792	2.0793	2.7516	3.0002	6.4915	6.4503	5.3079	5.5650	7.6495
10	Union North East Zone (previously Eastern Zone)	3.3217	2.2975	2.2890	2.3084	2.0792	2.0793	2.7516	3.0002	7.7619	7.7149	6.0365	6.3288	8.7597
11	Gas Supply Western Transportation (6)	1.8620	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Gas Supply Storage Service													
12	Union North West Zone (previously Fort Frances)	1.4544	2.2812	2.1252	2.0785	2.0265	2.0231	2.2005	2.0547	3.6786	3.6175	2.0636	2.1507	1.8724
13	Union North West Zone (previously Western Zone)	1.4544	2.2812	2.1252	2.0785	2.0265	2.0231	2.2005	2.0547	3.3463	3.2920	2.2941	2.3910	1.8700
14	Union North East Zone (previously Northern Zone)	1.4544	6.2598	5.8983	5.8201	5.0081	5.0482	6.3909	6.6690	3.9476	3.8899	3.0945	3.2252	2.2540
15	Union North East Zone (previously Eastern Zone)	1.4544	6.2598	5.8983	5.8201	5.0081	5.0482	6.3909	6.6690	4.4552	4.3952	3.4348	3.5799	2.5640
	Rate 10													
16	Monthly Charge - All Zones (5)	$80.00	$76.58	$73.92	$72.90	$71.68	$70.75	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00
	Monthly Delivery Charge - All Zones													
17	First 1,000 m³	7.3378	10.1913	9.1971	8.5108	8.3429	8.3869	7.9011	7.6688	7.2298	7.1390	7.2431	7.6318	6.0549
18	Next 9,000 m³	6.0146	8.3182	7.5040	6.9247	6.7677	6.7990	6.4155	6.2363	5.8947	5.8241	5.9134	6.2182	4.7882
19	Next 20,000 m³	5.2479	7.2328	6.5390	6.0384	5.9082	5.9715	5.7447	5.5647	5.2108	5.1033	5.1639	5.4120	4.0657
20	Next 70,000 m³	4.7664	6.5512	5.9215	5.4583	5.3299	5.3848	5.1855	5.0279	4.7160	4.6205	4.6776	4.8959	3.6033
21	Over 100,000 m³	2.9420	3.9687	3.5817	3.2598	3.1388	3.1615	3.0670	2.9942	2.8414	2.7914	2.8353	2.9407	1.8512
	Gas Supply Transportation Service (6)													
22	Union North West Zone (previously Fort Frances)	3.0492	3.9399	3.9398	4.0863	4.8013	4.8011	5.8487	6.0054	5.1333	5.0913	3.6363	3.8695	5.4555
23	Union North West Zone (previously Western Zone)	3.0492	3.9399	3.9398	4.0863	4.8013	4.8011	5.8487	6.0054	4.3016	4.2768	3.5873	3.8173	5.8639
24	Union North East Zone (previously Northern Zone)	3.0492	2.1115	2.1023	2.1170	1.9020	1.8993	2.5218	2.7620	5.8063	5.7729	4.7871	5.0941	7.2153
25	Union North East Zone (previously Eastern Zone)	3.0492	2.1115	2.1023	2.1170	1.9020	1.8993	2.5218	2.7620	7.0767	7.0376	5.5049	5.8579	8.3255
26	Gas Supply Western Transportation (6)	1.8620	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Gas Supply Storage Service													
27	Union North West Zone (previously Fort Frances)	1.2156	1.8104	1.6481	1.5189	1.5007	1.5184	1.6596	1.5437	2.4007	2.3829	1.1356	1.2015	1.1964
28	Union North West Zone (previously Western Zone)	1.2156	1.8104	1.6481	1.5189	1.5007	1.5184	1.6596	1.5437	2.0684	2.0574	1.3627	1.4418	1.1941
29	Union North East Zone (previously Northern Zone)	1.2156	4.6780	4.3063	4.0114	3.5148	3.5922	4.5520	4.7078	2.6697	2.6553	2.1512	2.2760	1.5796
30	Union North East Zone (previously Eastern Zone)	1.2156	4.6780	4.3063	4.0114	3.5148	3.5922	4.5520	4.7078	3.1773	3.1606	2.4865	2.6307	1.8907
	Rate 20													
31	Monthly Charge (5)	$1,000.00	$1,090.76	$1,042.67	$1,016.90	$986.42	$958.77	$860.69	$884.46	$932.79	$972.44	$987.27	$1,000.00	$777.19
	Delivery Demand Charge													
32	First 70,000 m³	40.9769	34.7968	33.8043	33.3824	32.7557	32.2947	28.6515	28.6326	29.3047	27.8909	27.8830	27.8179	20.0760
33	All over 70,000 m³	24.0965	20.4623	19.8786	19.6305	19.2619	18.9909	16.8485	16.8374	17.2326	16.4012	16.3966	16.3583	11.8057
	Delivery Commodity Charge													
34	First 852,000 m³	0.1439	0.7760	0.7570	0.7425	0.7057	0.6942	0.5384	0.5495	0.5891	0.5383	0.5423	0.5246	0.2617
35	All over 852,000 m³	0.1439	0.5645	0.5500	0.5337	0.5013	0.4918	0.3843	0.3952	0.4282	0.3922	0.3963	0.3803	0.1891
	Monthly Gas Supply Demand Charge													
36	Union North West Zone (previously Fort Frances)	18.2185	41.8848	41.6281	42.4566	47.9510	45.7852	56.0632	56.4242	55.7556	54.0801	21.9979	21.9979	49.3344
37	Union North West Zone (previously Western Zone)	18.2185	41.8848	41.6281	42.4566	47.9510	45.7852	56.0632	56.4242	34.5138	33.2652	24.8383	24.8397	57.0166
38	Union North East Zone (previously Northern Zone)	18.2185	43.3684	43.1158	42.9973	39.7379	37.6082	47.6267	50.1792	72.9435	71.4880	62.6086	62.6121	86.6848
39	Union North East Zone (previously Eastern Zone)	18.2185	43.3684	43.1158	42.9973	39.7379	37.6082	47.6267	50.1792	105.4062	103.7960	82.3638	82.3684	110.8603
	Gas Supply Commodity Transportation 1 (6)													
40	Union North West Zone (previously Fort Frances)	1.1669	2.5133	2.5017	2.5643	2.9283	2.9194	3.5201	3.6200	4.4802	4.3859	3.0513	3.0513	4.2612
41	Union North West Zone (previously Western Zone)	1.1669	2.5133	2.5017	2.5643	2.9283	2.9194	3.5201	3.6200	4.0146	3.9299	3.1266	3.1266	4.4236
42	Union North East Zone (previously Northern Zone)	1.1669	1.7764	1.7670	1.7768	1.2942	1.2954	2.2174	2.6498	4.8570	4.7675	3.9709	3.9709	5.1192
43	Union North East Zone (previously Eastern Zone)	1.1669	1.7764	1.7670	1.7768	1.2942	1.2954	2.2174	2.6498	5.5682	5.4755	4.4184	4.4184	5.6884
	Gas Supply Commodity Transportation 2 (6)													
44	Union North West Zone (previously Fort Frances)	1.1669	-	-	-	-	-	-	-	-	-	-	-	0.2893
45	Union North West Zone (previously Western Zone)	1.1669	-	-	-	-	-	-	-	-	-	-	-	0.2668
46	Union North East Zone (previously Northern Zone)	1.1669	-	-	-	-	-	-	-	-	-	-	-	0.4111
47	Union North East Zone (previously Eastern Zone)	1.1669	-	-	-	-	-	-	-	-	-	-	-	0.5383
48	Gas Supply Western Transportation (6)	1.8620	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Bundled Storage Service ($/GJ)													
49	Monthly Demand Charge	21.287	18.835	18.587	18.501	16.456	16.360	19.093	20.238	12.489	12.366	9.692	9.643	11.097
50	Commodity Charge	0.108	0.240	0.233	0.223	0.212	0.207	0.208	0.204	0.159	0.158	0.157	0.156	0.239

2012 to 2024 Annual Delivery Rates
Union North Rate Zone

Line No.	Particulars (cents/m³)	2024 EB-2022-0200 (1) January 1, 2024	2023 EB-2022-0133 (2) January 1, 2023	2022 EB-2022-0089 April 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (3) EB-2018-0305 November 1, 2019	2018 EB-2018-0253 October 1, 2018	2017 (4) EB-2017-0278 October 1, 2017	2016 EB-2016-0247 October 1, 2016	2015 EB-2015-0255 October 1, 2015	2014 EB-2014-0208 October 1, 2014	2013 EB-2013-0316 October 1, 2013	2012 EB-2012-0345 October 1, 2012
		(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Rate 25													
51	Monthly Charge	$368.56	$368.56	$350.19	$339.91	$327.82	$316.83	$289.76	$306.75	$331.70	$352.32	$360.72	$375.00	$189.32
	Delivery Charge - All Zones													
52	Maximum	4.7694	6.6934	6.0421	5.5703	5.4426	5.4792	5.2439	5.0909	4.7943	4.7185	4.7842	5.0206	3.7255
	Rate 100													
53	Monthly Charge (5)	$1,500.00	$1,620.86	$1,553.83	$1,520.96	$1,482.00	$1,448.19	$1,341.41	$1,372.75	$1,423.71	$1,464.29	$1,477.44	$1,500.00	$777.19
	Delivery Demand Charge													
54	All Zones	12.7365	19.9460	19.1421	18.9922	18.7270	18.5612	15.0877	15.1083	15.5220	15.3958	15.3755	15.3415	11.9158
	Delivery Commodity Charge													
55	All Zones	0.1191	0.2871	0.2765	0.2727	0.2682	0.2660	0.2200	0.2205	0.2252	0.2190	0.2162	0.2136	0.1595
	Monthly Gas Supply Demand Charge													
56	Union North West Zone (previously Fort Frances)	18.2185	75.2744	75.2938	78.5253	91.3301	90.5780	109.9130	114.2215	103.8605	102.9596	59.0298	59.0298	88.0846
57	Union North West Zone (previously Western Zone)	18.2185	75.2744	75.2938	78.5253	91.3301	90.5780	109.9130	114.2215	79.0784	78.6756	62.3453	62.3453	97.0663
58	Union North East Zone (previously Northern Zone)	18.2185	114.0459	114.0713	118.3621	125.8639	124.8695	154.8340	161.5404	123.9130	123.2688	106.4130	106.4130	131.6881
59	Union North East Zone (previously Eastern Zone)	18.2185	114.0459	114.0713	118.3621	125.8639	124.8695	154.8340	161.5404	161.7862	160.9615	129.4620	129.4620	159.8951
	Gas Supply Commodity Transportation 1 (6)													
60	Union North West Zone (previously Fort Frances)	1.1669	4.2342	4.2236	4.4026	5.1144	5.0723	6.1684	6.4075	7.1222	7.0810	5.4887	5.4887	7.8681
61	Union North West Zone (previously Western Zone)	1.1669	4.2342	4.2236	4.4026	5.1144	5.0723	6.1684	6.4075	6.7730	6.7390	5.5452	5.5452	7.9899
62	Union North East Zone (previously Northern Zone)	1.1669	6.5400	6.5235	6.7654	7.1855	7.1288	8.8587	9.2385	7.4048	7.3672	6.1784	6.1784	8.5116
63	Union North East Zone (previously Eastern Zone)	1.1669	6.5400	6.5235	6.7654	7.1855	7.1288	8.8587	9.2385	7.9382	7.8982	6.5140	6.5140	8.9385
	Gas Supply Commodity Transportation 2 (6)													
64	Union North West Zone (previously Fort Frances)	1.1669	-	-	-	-	-	-	-	-	-	-	-	0.2893
65	Union North West Zone (previously Western Zone)	1.1669	-	-	-	-	-	-	-	-	-	-	-	0.2668
66	Union North East Zone (previously Northern Zone)	1.1669	-	-	-	-	-	-	-	-	-	-	-	0.4111
67	Union North East Zone (previously Eastern Zone)	1.1669	-	-	-	-	-	-	-	-	-	-	-	0.5383
68	Gas Supply Western Transportation (6)	1.8620	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Bundled Storage Service ($/GJ)													
69	Monthly Demand Charge	21.287	18.835	18.587	18.501	16.456	16.360	19.093	20.238	12.489	12.366	9.692	9.643	11.097
70	Commodity Charge	0.108	0.240	0.233	0.223	0.212	0.207	0.208	0.204	0.159	0.158	0.157	0.156	0.239

Notes:
(1) 2024 Rates as proposed, updated May 18, 2023.
(2) 2023 Rates at April 2022 QRAM (EB-2022-0133) per Exhibit 8, Tab 2, Schedule 8, Attachment 2.
(3) Annual rates for 2019 were implemented November 1, 2019.
(4) In 2017, Cap-and-Trade charges were included in delivery charges within the approved rate schedules. The Cap-and-Trade charges have been excluded from this attachment for comparability.
(5) The monthly customer charge excludes the $1 per month charge for Bill 32.
(6) For 2024, the gas supply transportation rates are proposed to be applicable to sales service and Dawn bundled direct purchase customers and the gas supply transportation Western rate is proposed to be applicable to Empress bundled direct purchase customers

2012 to 2024 Annual Delivery Rates
Union South Rate Zone

Line No.	Particulars (cents/m³)	2024 EB-2022-0200 (1) January 1, 2024	2023 EB-2022-0133 (2) January 1, 2023	2022 EB-2022-0089 April 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (3) EB-2018-0305 November 1, 2019	2018 EB-2018-0253 October 1, 2018	2017 (4) EB-2017-0278 October 1, 2017	2016 EB-2016-0247 October 1, 2016	2015 EB-2015-0255 October 1, 2015	2014 EB-2014-0208 October 1, 2014	2013 EB-2013-0316 October 1, 2013	2012 EB-2012-0345 October 1, 2012
		(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Rate M1													
1	Monthly Charge (5)	$25.19	$22.98	$22.18	$21.87	$21.50	$21.22	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00	$21.00
	Monthly Delivery Commodity Charge													
2	First 100 m³	11.1536	6.5344	6.1255	5.8445	5.4885	5.3290	5.0777	4.6950	4.1132	3.8988	3.8252	3.7286	3.5197
3	Next 150 m³	10.6398	6.2203	5.8309	5.5598	5.2131	5.0555	4.8140	4.4539	3.9046	3.7017	3.6263	3.5221	3.3252
4	All over 250 m³	9.3121	5.4088	5.0702	4.8243	4.5020	4.3487	4.1326	3.8309	3.3656	3.1926	3.1298	3.0336	2.8652
5	Storage Service	Note (10)	0.9025	0.8339	0.8018	0.7692	0.7643	0.7331	0.7153	0.7027	0.7416	0.7491	0.7368	0.9735
6	Gas Supply Transportation Charge (11)	1.8069	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate M2													
7	Monthly Charge (5)	$80.00	$76.58	$73.92	$72.90	$71.68	$70.75	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00
	Monthly Delivery Commodity Charge													
8	First 1,000 m³	8.7514	6.2404	5.6680	5.2510	4.9531	4.9507	5.0510	4.6695	4.0507	3.6124	3.6225	4.0899	3.7162
9	Next 6,000 m³	8.6038	6.1308	5.5686	5.1579	4.8626	4.8581	4.9552	4.5818	3.9755	3.5455	3.5557	4.0136	3.6373
10	Next 13,000 m³	8.1002	5.7571	5.2432	4.8662	4.5932	4.6186	4.7739	4.3949	3.7869	3.3563	3.3608	3.7862	3.4022
11	All over 20,000 m³	7.5749	5.3672	4.8884	4.5329	4.2686	4.2840	4.4236	4.0755	3.5152	3.1163	3.1215	3.5133	3.1201
12	Storage Service	Note (10)	0.8511	0.7589	0.7017	0.6709	0.6730	0.6483	0.6252	0.6161	0.6428	0.6624	0.7550	0.7172
13	Gas Supply Transportation Charge (11)	1.6963	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate M4													
	Monthly demand charge:													
14	First 8,450 m³	63.1395	69.3946	67.0195	65.6379	64.1235	62.1743	61.6487	56.9923	52.9231	47.8404	46.8295	46.6239	45.2527
15	Next 19,700 m³	30.0779	33.0577	31.9927	31.3732	30.1975	28.6379	27.6418	25.5539	23.7294	21.4504	20.9972	20.9050	19.6336
16	All over 28,150 m³	25.7818	28.3360	27.4413	26.9208	25.7891	24.2801	23.2229	21.4688	19.9360	18.0214	17.6406	17.5631	16.3047
	Monthly delivery commodity charge:													
17	First block	1.3268	2.0339	1.8943	1.7054	1.4604	1.4141	1.5493	1.3803	1.2454	1.0353	0.9945	0.9238	0.5564
18	All remaining use	0.1654	0.8725	0.8027	0.6738	0.5307	0.5085	0.5919	0.5586	0.5301	0.4466	0.4365	0.3860	0.2173
	Interruptible service													
19	Monthly Charge (5)	$500.00	$755.88	$725.48	$711.40	$694.73	$680.71	$644.34	$654.15	$669.55	$681.21	$683.97	Note (6)	Note (6)
	Daily delivery commodity charge:													
20	2,400 m³ to 17,000 m³	2.2121	3.5886	3.4115	3.2443	2.9928	2.8510	3.0257	2.9902	3.0056	2.6539	2.5883	Note (6)	Note (6)
21	17,000 m³ to 30,000 m³	2.0822	3.4587	3.2816	3.1144	2.8629	2.7211	2.8958	2.8603	2.8757	2.5240	2.4584	Note (6)	Note (6)
22	30,000 m³ to 50,000 m³	2.0139	3.3904	3.2133	3.0461	2.7946	2.6528	2.8275	2.7920	2.8074	2.4557	2.3901	Note (6)	Note (6)
23	50,000 m³ to 60,000 m³	1.9660	3.3425	3.1654	2.9982	2.7467	2.6049	2.7796	2.7441	2.7595	2.4078	2.3422	Note (6)	Note (6)
24	Gas Supply Transportation Charge (11)	1.4501	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate M5													
	Firm service													
25	Monthly demand charge	40.0023	41.2157	40.1849	40.3016	37.6710	36.4546	34.4858	31.7959	30.7027	28.5955	28.3977	28.6252	27.4318
26	Monthly delivery commodity charge	3.7534	3.5497	2.7867	2.6432	2.4277	2.3100	2.3415	2.3315	2.2944	2.0180	1.9510	1.9007	2.1298
	Interruptible service													
27	Monthly Charge (5)	$500.00	$755.88	$725.48	$711.40	$694.73	$680.71	$644.34	$654.15	$669.55	$681.21	$683.97	$690.00	$498.20
	Daily delivery commodity charge:													
28	2,400 m³ to 17,000 m³	2.2121	3.5886	3.4115	3.2443	2.9928	2.8510	3.0257	2.9902	3.0056	2.6539	2.5883	Note (7)	Note (7)
29	17,000 m³ to 30,000 m³	2.0822	3.4587	3.2816	3.1144	2.8629	2.7211	2.8958	2.8603	2.8757	2.5240	2.4584	Note (7)	Note (7)
30	30,000 m³ to 50,000 m³	2.0139	3.3904	3.2133	3.0461	2.7946	2.6528	2.8275	2.7920	2.8074	2.4557	2.3901	Note (7)	Note (7)
31	50,000 m³ to 60,000 m³	1.9660	3.3425	3.1654	2.9982	2.7467	2.6049	2.7796	2.7441	2.7595	2.4078	2.3422	Note (7)	Note (7)
32	Gas Supply Transportation Charge (11)	0.9419	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate M7													
	Firm service													
33	Monthly demand charge	39.5821	34.0345	33.5024	34.7967	34.8069	35.2413	34.6517	30.8246	27.6801	26.3233	25.5491	25.3924	25.1902
34	Monthly delivery commodity charge	0.4488	0.4538	0.3998	0.3263	0.2483	0.2577	0.3372	0.4161	0.3734	0.3410	0.3249	0.2814	0.0694
	Interruptible service													
	Monthly delivery commodity charge:													
35	Maximum	7.7319	7.1413	6.3901	6.4518	6.3181	6.4032	6.4334	5.5963	4.9691	4.2954	4.0364	3.9063	2.4356
	Seasonal service													
	Monthly delivery commodity charge:													
36	Maximum	7.4394	6.8972	6.1460	6.2077	6.0740	6.1591	6.1893	5.3522	4.7250	4.0513	3.7923	3.6622	2.1915
37	Gas Supply Transportation Charge (11)	1.5901	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate M9													
38	Monthly demand charge	30.2537	27.2284	26.2240	26.1582	24.3598	25.1842	23.5428	22.3154	17.4339	16.2405	15.2792	15.1688	16.8055
39	Monthly delivery commodity charge	0.3672	0.304	0.2856	0.2059	0.1353	0.1284	0.1569	0.2425	0.1902	0.2019	0.1964	0.1580	0.2152
40	Gas Supply Transportation Charge (11)	1.2602	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate M10													
41	Monthly delivery commodity charge	Note (9)	8.9527	8.2767	7.9620	7.6393	7.5095	7.1560	6.7547	5.9327	5.4186	4.9340	5.1133	2.5032

2012 to 2024 Annual Delivery Rates
Union South Rate Zone

Line No.	Particulars (cents/m³)	2024 EB-2022-0200 (1) January 1, 2024	2023 EB-2022-0133 (2) January 1, 2023	2022 EB-2022-0089 April 1, 2022	2021 EB-2021-0219 October 1, 2021	2020 EB-2020-0195 October 1, 2020	2019 (3) EB-2018-0305 November 1, 2019	2018 EB-2018-0253 October 1, 2018	2017 (4) EB-2017-0278 October 1, 2017	2016 EB-2016-0247 October 1, 2016	2015 EB-2015-0255 October 1, 2015	2014 EB-2014-0208 October 1, 2014	2013 EB-2013-0316 October 1, 2013	2012 EB-2012-0345 October 1, 2012
		(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Rate T1													
42	Monthly Charge (5)	$3,000.00	$2,155.61	$2,074.16	$2,039.01	$1,997.27	$1,963.32	$1,896.28	$1,905.94	$1,924.04	$1,935.18	$1,932.35	$1,936.13	$1,793.52
	Storage ($ / GJ)													
	Monthly demand charges:													
43	Firm space	0.016	0.012	0.012	0.012	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.010
	Firm Injection/Withdrawal Right													
44	Customer provides deliverability inventory	2.549	1.473	1.415	1.388	1.355	1.327	1.184	1.186	1.195	1.208	1.210	1.197	1.012
	Commodity charges:													
45	Customer provides compressor fuel - Withdrawal	-	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	0.007
46	Customer provides compressor fuel - Injection	-	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	0.007
47	Storage fuel ratio - customer provides fuel	0.836%	0.445%	0.430%	0.424%	0.417%	0.412%	0.408%	0.406%	0.403%	0.400%	0.397%	0.395%	0.597%
	Transportation (cents / m³)													
48	Monthly demand charge first 28,150 m³	37.2863	44.5954	43.5565	43.3948	42.4963	41.3430	40.5921	35.4376	32.5602	32.7527	32.1516	31.9554	19.0307
49	Monthly demand charge next 112,720 m³	26.5129	31.6763	30.9585	30.8466	29.9909	28.9074	28.0445	24.4833	22.4954	22.6284	22.2131	22.0775	13.0041
	Firm commodity charges:													
50	Customer provides compressor fuel - All volumes	-	0.1400	0.1313	0.1117	0.1054	0.1035	0.1051	0.1527	0.0760	0.0739	0.0720	0.0712	0.1127
	Interruptible commodity charges:													
51	Maximum - customer provides compressor fuel	7.7319	7.0675	6.3178	6.3941	6.2762	6.3661	6.3905	5.5541	4.9116	4.2358	3.9841	3.8610	2.3303
52	Transportation fuel ratio - customer provides fuel	0.802%	0.358%	0.351%	0.341%	0.338%	0.326%	0.323%	0.305%	0.303%	0.301%	0.251%	0.250%	0.554%
	Rate T2 (8)													
53	Monthly Charge (5)	$3,000.00	$6,803.81	$6,500.02	$6,338.15	$6,147.68	$5,975.36	$5,440.88	$5,513.81	$5,751.12	$5,943.28	$6,013.02	$6,000.00	Note (8)
	Storage ($ / GJ)													
	Monthly demand charges:													
54	Firm space	0.016	0.012	0.012	0.012	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	Note (8)
	Firm Injection/Withdrawal Right													
55	Customer provides deliverability inventory	2.549	1.473	1.415	1.388	1.355	1.327	1.184	1.186	1.195	1.208	1.210	1.197	Note (8)
	Commodity charges:													
56	Customer provides compressor fuel - Withdrawal	-	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	Note (8)
57	Customer provides compressor fuel - Injection	-	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	Note (8)
58	Storage fuel ratio - customer provides fuel	0.836%	0.445%	0.430%	0.424%	0.417%	0.412%	0.408%	0.406%	0.403%	0.400%	0.397%	0.395%	Note (8)
	Transportation (cents / m³)													
59	Monthly demand charge first 140,870 m³	38.1045	33.1606	32.7085	32.8334	32.0677	32.0079	32.0198	26.4455	22.7402	20.9163	20.3436	20.1911	Note (8)
60	Monthly demand charge all over 140,870 m³	21.4843	18.4774	18.2383	18.3043	17.4997	17.3851	16.9369	13.9884	12.0285	11.0637	10.7608	10.6802	Note (8)
	Firm commodity charges:													
61	Customer provides compressor fuel - All volumes	-	0.0306	0.0254	0.0214	0.0199	0.0200	0.0234	0.0521	0.0082	0.0080	0.0078	0.0078	Note (8)
	Interruptible commodity charges:													
62	Maximum - customer provides compressor fuel	7.7319	7.0776	6.3283	6.4015	6.2818	6.3701	6.3942	5.5572	4.9157	4.2400	3.9848	3.8615	Note (8)
63	Transportation fuel ratio - customer provides fuel	0.802%	0.309%	0.300%	0.297%	0.293%	0.291%	0.295%	0.283%	0.282%	0.279%	0.248%	0.247%	Note (8)
	Rate T3													
64	Monthly Charge - City of Kitchener	$30,982.14	$22,703.73	$21,833.55	$21,450.63	$20,996.25	$20,622.21	$19,843.96	$19,968.19	$20,208.17	$20,369.55	$20,358.77	$20,371.35	$17,549.76
	Storage ($ / GJ)													
	Monthly demand charges:													
65	Firm space	0.016	0.012	0.012	0.012	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.010
	Firm Injection/Withdrawal Right													
66	Customer provides deliverability inventory	2.549	1.473	1.415	1.388	1.355	1.327	1.184	1.186	1.195	1.208	1.210	1.197	1.012
	Commodity charges:													
67	Customer provides compressor fuel - Withdrawal	-	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	0.007
68	Customer provides compressor fuel - Injection	-	0.012	0.012	0.012	0.012	0.012	0.008	0.008	0.008	0.008	0.008	0.008	0.007
69	Storage fuel ratio - customer provides fuel	0.836%	0.419%	0.430%	0.424%	0.417%	0.412%	0.408%	0.406%	0.403%	0.400%	0.397%	0.395%	0.597%
	Transportation (cents / m³)													
70	Monthly demand charge	25.2313	20.7133	19.8760	19.5508	18.4402	17.9741	17.9898	16.7213	11.6340	10.4499	9.4605	9.3582	8.9901
	Firm commodity charges:													
71	Customer provides compressor fuel - All volumes	-	0.0821	0.0738	0.0526	0.0475	0.0531	0.0569	0.1339	0.0108	0.0108	0.0107	0.0107	0.0681
72	Transportation fuel ratio - customer provides fuel	0.802%	0.419%	0.411%	0.404%	0.401%	0.402%	0.412%	0.380%	0.378%	0.375%	0.286%	0.285%	0.722%

Notes:
(1) Proposed 2024 Rates, updated May 18, 2023.
(2) 2023 Rates at April 2022 QRAM (EB-2022-0133).
(3) Annual rates for 2019 were implemented November 1, 2019.
(4) In 2017, Cap-and-Trade charges were included in delivery charges within the approved rate schedules. The Cap-and-Trade charges have been excluded from this attachment for comparability.
(5) The monthly customer charge excludes the $1 per month charge for Bill 32.
(6) Rate M4 interruptible service was effective January 1, 2014.
(7) The current Rate M5 commodity blocking structure was effective January 1, 2014.
(8) Rate T2 was effective January 1, 2013.
(9) Rate M10 is proposed for elimination in 2024.
(10) For 2024, the Rate M1 and Rate M2 storage charges are included in delivery charges.
(11) The gas supply transportation charge is proposed for 2024.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

(further to the response provided to undertaking JT3.10)

a) Could EGI please provide the cost in 2023 of its fugitive emission direct measurement activities, and a brief description of the scope of those activities (i.e. number of facilities tested, any more information on types of facilities tested, sampling protocols to identify those facilities to be tested).

b) Does EGI have any information on the potential cost of aerial, satellite or tower direct measurement approaches (relative to the costs of EGI's current program for direct measurement of fugitive emissions)?

c) What is the scope, form and expected completion of the evaluation as noted in the undertaking response of the various technologies and initiatives, and the feasibility of conducting aerial (including satellite and tower) testing?

Response:

a) Under the federal methane regulation (Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)), Enbridge Gas performs leak surveys three times per year at 41 applicable facilities, as defined by the methane regulation, including applicable compressor stations, storage measurement stations, and meter and receipt stations. Leaks found during these leak surveys are quantified using a hi-flow sampler. Costs for the 2023 measurement work are estimated to be $300,000. This estimate does not include internal labour or repair costs.

b) Enbridge Gas does not have information about the potential costs related to the use of aerial, satellite or tower direct measurement at this time.

c) Enbridge Gas expects to complete a preliminary technology review by the end of 2023. This desktop review will consider various technologies available, such as mobile, aerial and satellite. The results of this review will inform next steps, including the feasibility of conducting aerial testing and associated costs.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

As a follow-up to our UFG question Exhibit I.ADR.15 b): How are they determined, measured, estimated or simply ultimately arrived at for reporting purposes?

Please provide the amount of actual emissions arrived at for the last 3 years.

Response:

As part of its federal and provincial annual GHG emissions reporting requirements, Enbridge Gas reports its fugitive emissions. Enbridge Gas uses these fugitive emissions estimates to distinguish the portion of UFG related to leaks. These fugitive emissions are calculated in accordance with the provincial and federal GHG reporting programs, including the use of industry and company-specific emission factors as well as the use of direct measurements (using hi-flow sampler to quantify emissions).

UFG Leak Emissions

Line No.	Particulars	Utility	2020 Actual	2021 Actual	2022 Actual
			(b)	(c)	(d)
1	UAF / LUF Leak Emissions	EGD (1)	279,671	291,396	235,661
2	UFG Leak Emissions	Union (2)	131,496	143,618	175,336
4	Total (tCO2e)		411,166	435,013	410,997

Note:
(1) EGD rate zone.
(2) Union rate zones.
(3) 2022 emissions calculated using IPCC AR5 global warming potentials, whereas 2020 and 2021 emissions were calculated using IPCC AR4 global warming potentials, in accordance with federal and provincial reporting regulations.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

For the APCDA category of *Amortized Gas Supply Storage and Transportation Costs,* please provide any evidentiary references on the calculation of the proposed deferral account amount.

Whether provided or not, please provide the calculation of the proposed balance by including actuals for 2022 and 2023 as much as available and forecast for the rest of the 2023 year

Response:

Please see Attachment 1 for the calculation of the Amortized Gas Supply Storage and Transportation Costs balance in the APCDA:

- Table 1 provides the calculation of the 2022 Forecast balance of $64.9 million recorded in the APCDA per Exhibit 9, Table 2, Schedule 1, Attachment 2.
- Table 2 provides the calculation 2022 Actual balance of $62.1 million recorded in the APCDA.
- Table 3 provides the calculation of the 2023 Forecast balance of $62.1 million. The 2023 ending balance is equivalent to the 2022 Actual balance because no additional amounts are proposed to be recorded in the APCDA in 2023. See Exhibit 9, Tab 2, Schedule 1 pages 14 to 16 for additional details.

Table 1: Amortized Gas Supply Storage and Transportation Costs in APCDA - 2022 Forecast

Line No.	Particulars ($ millions)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec (2)	Total
1	Opening Balance - Gas Supply Storage and Transportation Costs Balance Sheet Account	61.4	31.4	8.4	0.0	11.9	23.9	36.1	48.4	60.7	72.9	84.7	82.0	
2	Gas Supply Storage and Transportation Costs	12.7	12.7	12.7	12.8	12.9	13.1	13.2	13.1	13.1	12.8	12.7	12.7	154.6
3	Gas Supply Storage and Transportation Costs Variance Recorded in S&TDA	(0.9)	(0.8)	(0.9)	(1.0)	(0.9)	(0.9)	(0.8)	(0.9)	(0.9)	(0.9)	(1.1)	(1.1)	(11.1)
4	Net Gas Supply Storage and Transportation Costs Recorded in Balance Sheet Account	11.8	11.9	11.8	11.9	12.0	12.2	12.3	12.3	12.2	11.8	11.6	11.6	143.4
5	Amortized Gas Supply Storage and Transportation Costs Expensed	(41.9)	(34.9)	(20.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(14.3)	(28.7)	(139.9)
6	Closing Balance - Gas Supply Storage and Transportation Balance Sheet Account (1)	31.4	8.4	0.0	11.9	23.9	36.1	48.4	60.7	72.9	84.7	82.0	0.0	
7	Closing Balance - APCDA (2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.9	

Notes:

(1) Line 1 + Line 4 + Line 5

(2) Forecast December 2022 closing balance transferred to APCDA (Exhibit 9, Table 2, Schedule 1, Attachment 2)

Table 2: Amortized Gas Supply Storage and Transportation Costs in APCDA - 2022 Actual

Line No.	Particulars ($ millons)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec (2)	Total
1	Opening Balance - Gas Supply Storage and Transportation Costs Balance Sheet Account	61.4	31.0	7.6	(2.0)	11.2	22.7	34.5	46.1	57.9	69.1	80.3	78.6	
2	Gas Supply Storage and Transportation Costs	12.3	12.7	12.3	10.5	12.8	12.7	11.0	12.6	12.3	11.6	13.1	12.1	145.9
3	Gas Supply Storage and Transportation Costs Variance Recorded in S&TDA	(0.8)	(1.3)	(1.0)	0.7	(1.3)	(0.9)	0.6	(0.9)	(1.1)	(0.4)	(0.9)	(0.9)	(8.1)
4	Net Gas Supply Storage and Transportation Costs Recorded in Balance Sheet Account	11.4	11.4	11.3	11.2	11.5	11.8	11.6	11.8	11.2	11.2	12.2	11.2	137.9
5	Amortized Gas Supply Storage and Transportation Costs Expensed	(41.9)	(34.9)	(20.9)	2.0	0.0	0.0	0.0	0.0	0.0	0.0	(13.8)	(27.7)	(137.1)
6	Closing Balance - Gas Supply Storage and Transportation Balance Sheet Account (1)	31.0	7.6	(2.0)	11.2	22.7	34.5	46.1	57.9	69.1	80.3	78.6	0.0	
7	Closing Balance - APCDA (2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.1	

Notes:

(1) Line 1 + Line 4 + Line 5

(2) December 2022 closing balance transferred to APCDA

Table 3: Amortized Gas Supply Storage and Transportation Costs in APCDA - 2023 Forecast

Line No.	Particulars ($ millons)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
		Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
1	Opening Balance - APCDA	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	
2	Gas Supply Storage and Transportation Costs	12.3	12.4	12.3	12.8	12.0	12.1	12.2	12.2	12.3	12.2	12.1	12.0	146.9
3	Gas Supply Storage and Transportation Costs Variance Recorded in S&TDA	(0.9)	(1.0)	(0.9)	(1.4)	(0.6)	(0.7)	(0.8)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(10.5)
4	Net Gas Supply Storage and Transportation Costs Expensed (1)	11.4	11.4	11.4	11.4	11.4	11.4	11.5	11.4	11.4	11.3	11.2	11.2	136.4
5	Closing Balance - APCDA	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	62.1	

Notes:
(1) Amounts expensed as incurred starting 2023. No additional amounts recorded in APCDA in 2023. Please see Exhibit 9, Tab 2, Schedule 1, pages 14 to 16 for additional details.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

For the responses from Exhibit I.ADR.36, it is our view that the weather risk of needing empty storage to account for weather variation is correlated with full storage which passes in November. Even adding an additional “contingency”, this risk passes by mid-December allowing a holiday season fill with fixed price gas. Why is this not factual.

a) Similarly, the hysteresis effects are very important at the end of the injection season, therefore the risk passes by mid-December.

The premise in this scenario is that if the gas is not otherwise used for in March or April, the space would be emptied by utilizing the gas as a reduction in Load Balancing gas purchased in the following summer.

Response:

Enbridge Gas is proposing to maintain operational contingency space of 4.8 PJ in order to manage late season injections in addition to other factors. While Enbridge Gas agrees that the risks for which this space is held empty diminish once winter season withdrawals commence, they are not completely eliminated.

In addition, Enbridge Gas does not agree with a planned purchasing strategy whereby the 4.8 PJ of contingency space would be filled after the injection season is complete and planning to use that gas as a reduction in load balancing purchases in the subsequent summer. In a normal winter, this would not be a cost-effective strategy for managing load balancing requirements as gas purchased in the winter is more expensive than gas purchased in the summer.

The paragraph above explains how Enbridge Gas has planned to meet demands. Operationally, Enbridge Gas makes its procurement decisions based on weather, customer demands, its supply position, and economic conditions and will execute at the appropriate time. These decisions may deviate from Enbridge Gas’s planned procurement over the course of a gas year.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

For the responses from Exhibit I.ADR.38, in very simple terms does the purchase profile of Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 5 of 6 provide approximately 30 TJ of summer-winter load balancing?

b) Does this exhibit represent EGI's current gas supply plan for the winter of 2023/24?

Response:

The 2024 Load Balancing Calculations schedule, provided at Exhibit 4, Tab 2, Schedule 1, Attachment 1, page 5, line 4, columns d) to j), sum to a total of 26 PJ.

a) No, this does not represent Enbridge Gas's current Gas Supply Plan for the winter 2023/2024. Enbridge Gas's Gas Supply Plan for the winter 2023/2024 is based on existing methodologies.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Reference - Exhibit JT8.14

a) How did you develop General Operations and Engineering to be 55% of total direct costs?
b) What is the current level on a percentage basis of General Operations and Engineering in your current Union South Rate classes?

Response:

a) Please see Table 1 for the derivation of the general operating and engineering costs as a percentage of other O&M expense. The percentage has been updated to 45% based on the updated 2024 Cost Allocation Study provided at Exhibit I.7.0-STAFF-237, updated May 18, 2023.

Table 1
Distribution Customer Stations General Operations & Engineering Percentage

Line No.	Particulars	Total ($000s) (a)
	Distribution Customer Stations	
1	O&M Expenses excluding General Operations & Engineering	10,342
2	General Operations & Engineering (1)	4,695
3	Total O&M Expenses (2)	15,038
4	General Operations & Engineering Percentage (3)	45%

Notes:
(1) Exhibit I.7.0-STAFF-237, Attachment 1.7, p. 3, column (m), line 89.
(2) Exhibit I.7.0-STAFF-237, Attachment 1.7, p. 3, column (m), line 102.
(3) Line 2 / line 1.

Updating the general operations & engineering and vehicles percentages[1] used in the derivation of the Rate M13 monthly fixed charge results in decrease of $334 and $755 for total annual costs of $5,297 and $11,984 for a typical and

[1] Indirect percentages updated based on the 2024 Cost Allocation Study updated May 18, 2023, provided at Exhibit I.7.0-STAFF-237, Attachment 1.

large producer station, respectively, relative to the total annual costs provided at Exhibit JT8.14, Table 1. Table 2 provides the updated derivation of the Rate M13 monthly fixed charge per customer station.

Table 2
Derivation of Rate M13 Monthly Fixed Charge Per Customer Station

Line No.	Particulars	Typical Customer Station Hours	Typical Customer Station Cost ($)	Large Customer Station Hours	Large Customer Station Cost ($)
		(a)	(b)	(c)	(d)
	Direct Costs (1)				
1	Compliance Inspection	14	1,939	35	4,848
2	Maintenance	5	693	14	1,939
	Other Costs				
3	Data Entry & Travel	1	139	1	139
4	Weed Spraying (2)		100		180
5	Station Painting (2)		530		530
6	Total Direct Costs		3,400		7,635
	Indirect Costs				
7	General Operations & Engineering (3)		1,544		3,466
8	Vehicles (4)		353		883
9	Total Indirect Costs		1,897		4,349
10	Total Annual Costs (line 6 + line 9)		5,297		11,984
11	Number of Customer Stations (5)		66		9
12	Total Operating and Maintenance Costs ($000s) (line 10 x line 11)		350		105

Notes:
(1) Total direct costs, where applicable, calculated as the number of hours per task multiplied by the fully allocated hourly rate for a station technician of $139/hour.
(2) Weed spraying costs based on incurred annual expense and station painting cost based on the average annual cost of the station painting program.
(3) Indirect cost for general operations and engineering calculated as 45% of total direct costs (line 6).
(4) Indirect cost for vehicles calculated as 13% of total direct labour related costs (line 1 + line 2 + line 3).
(5) Exhibit 8, Tab 2, Schedule 8, Attachment 14, lines 2 and 5.

b) In Union’s 2013 Cost Allocation Study, the general operations & engineering costs on a percentage basis for Union South rate classes is approximately 10%

with no costs allocated to Rate M13. The comparable average general operations & engineering costs on a percentage basis in Enbridge Gas's 2024 Cost Allocation Study is 23%.

The general operations & engineering costs as a percentage of other O&M expenses of 45% included in Table 1 and used in the derivation of the 2024 Rate M13 total annual cost per customer station is based on the general operations & engineering costs for distribution customer stations[2]. Enbridge Gas has included a contribution towards the recovery of the general operations & engineering costs in the Rate M13 rate design as these costs are partly incurred to provide the service. This rate design is also consistent with the costs allocated to all other customer stations in the 2024 Cost Allocation Study. The general operations & engineering costs includes asset management, damage prevention, stations engineering, gas supply, capacity management and gas control operations.

[2] Allocation percentage specific to the Distribution Customer Stations functional classification in the 2024 Cost Allocation Study provided at Exhibit I.7.0-STAFF-237, Attachment 1.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

Wanting to ensure that 62.1 M actuals in account are valid. Since accounting change, there should be no change over time that customers are paying. That this is just a timing issue, not additional money. 9.1-SEC-230 part b i & ii), response is confusing. Goal is to ensure rate payers are not paying more.

Response:

Confirmed that the $62.1 million balance in the APCDA represents a timing issue and ratepayers are not paying more as a result of the accounting policy change. Please see Attachment 1 which illustrates the following:

- EGD rate zone's Gas Supply and Transportation costs were previously accumulated in a balance sheet account between April-October 2021 and expensed between November 2021-March 2022;
- Similarly, Gas Supply and Transportation costs accumulated in a balance sheet account between April-October 2022, with a portion of the costs expensed in November and December 2022.
- The remaining balance of $62.1 million at December 2022 was not expensed in January to March 2023 as would have been done under the previous accounting treatment. These costs are proposed to only be recovered through the clearance of the APCDA deferral account.
- As such, there is no double recovery of the costs in 2023, upon Enbridge Gas switching to the new methodology of expensing the costs monthly as incurred.

Gas Supply Storage and Transportation Costs

Line No.	Particulars ($ millions)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	2021												
1	Opening balance - 2021	59.4	29.3	6.2	-	11.3	22.7	34.3	46.1	57.6	69.4	81.0	78.2
2	Add: Monthly net gas supply storage and transportation costs	11.4	11.4	11.4	11.3	11.4	11.6	11.8	11.6	11.8	11.5	11.2	11.2
3	Less: Amounts expensed as incurred (Jan-Mar, Nov-Dec)	(11.4)	(11.4)	(11.4)	-	-	-	-	-	-	-	(11.2)	(11.2)
4	Less: Amortization of Opening balance	(30.1)	(23.1)	(6.2)	-	-	-	-	-	-	-	(2.8)	(16.8)
5	Closing balance - 2021	29.3	6.2	-	11.3	22.7	34.3	46.1	57.6	69.4	81.0	78.2	61.4
	2022												
6	Opening balance - 2022	61.4	31.0	7.6	(2.0)	11.2	22.7	34.5	46.1	57.9	69.1	80.3	78.6
7	Add: Monthly net gas supply storage and transportation costs	11.4	11.4	11.3	11.2	11.5	11.8	11.6	11.8	11.2	11.2	12.2	11.2
8	Less: Amounts expensed as incurred (Jan-Mar, Nov-Dec)	(11.4)	(11.4)	(11.3)	-	-	-	-	-	-	-	(12.2)	(11.2)
9	Less: Amortization of Opening balance	(30.4)	(23.4)	(9.6)	2.0	-	-	-	-	-	-	(1.7)	(16.5)
10	Closing balance - 2022	31.0	7.6	(2.0)	11.2	22.7	34.5	46.1	57.9	69.1	80.3	78.6	62.1
	2023												
11	Monthly net gas supply storage and transportation costs, expensed as incurred	11.4	11.4	11.4	11.4	11.4	11.4	11.5	11.4	11.4	11.3	11.2	11.2

Notes:

(1) 2021 Opening balance of $59.4M (Line 1, column a) represents costs accumulated from Apr-Dec 2020 that have not yet been expensed. This Opening balance is expensed during Jan-Mar 2021 (Line 4, columns a to c).

(2) 2021 Closing balance of $61.4M (Line 5, column l) represents costs accumulated from Apr-Dec 2021 that have not yet been expensed (Line 2 ∑(columns d to j) less Line 4 ∑(columns k to l)).

(3) 2022 Opening balance of $61.4M (Line 6, column a) is expensed during Jan-Mar 2022 (Line 9, columns a to c + adjustment in d).

(4) 2022 Closing balance of $62.1M (Line 10, column l) represents costs accumulated from Apr-Dec 2022 that have not yet been expensed (Line 7 ∑(columns d to j) less Line 9 ∑(columns k to l)). This balance was transferred to the APCDA.

(5) Starting 2023, amounts are expensed as incurred (Line 11). There is no amortization of the $62.1M balance that was transferred to the APCDA.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

With reference to the responses provided to Exhibit I.ADR.44 with included spreadsheet,

The spreadsheet provides line items that refer to “Gas Supply Storage and Transportation Costs”. Specific to the Gas Supply Transportation Costs, we understand that these have been defined in evidence (Ex.9, Exhibit 9, Tab 2, Schedule 1 page 14) as “transportation capacity to transport gas to and from storage”. From a simplistic view, storage accepts gas surplus to seasonal demands from transport of many different pipes.

a) What distinguishes the pipes that were allocated to this account?
b) Are there any gas commodity costs included in this account?
c) Are there any clearance of the transportation pipes associated with transport gas to and from storage, in whole or in part, to QRAM-related costs including the PGVA?
d) Are there any gas commodity costs associated with Load Balancing gas cleared, in whole or in part, to QRAM-related costs including the PGVA?

Response:

a) The amortized transportation costs that were recorded in the APCDA are limited to the costs of the Dawn Parkway system capacity held by the EGD rate zone that are used to transport supply to/from storage to serve the Enbridge CDA and Enbridge EDA. For clarity, only amounts that were not recovered from ratepayers through the disposition of the S&TDA due to the accounting policy change discussed at Exhibit 9, Tab 2, Schedule 1 have been included in the APCDA.

b) No.

c) The variances for upstream transportation costs associated with transporting gas to/from storage are recorded in the following QRAM related deferral accounts:

- EGD - PGVA (Account No. 179-70_)
- Union North West - Transportation Tolls and Fuel (Account No. 179-145)
- Union North East - Transportation Tolls and Fuel (Account No. 179-146)

None of these upstream transportation costs are recorded in the APCDA. Only amortized costs as laid out in part a) of this response were recorded in the APCDA.

d) There are no gas commodity costs associated with load balancing included in the APCDA. All gas commodity cost associated with load balancing activities are recovered in the PGVA as part of QRAM.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question:

a) Does the cost of debt apply to 100% of the integration capital left in rate base ($118 million) or only to 64% of that rate base amount?

b) What is the amount of depreciation associated with the remaining integration capital left in rate base for each of 2024 and the four following years.

Response:

a) The cost of debt would apply to 64% of the rate base value, depending on the applicable equity thickness.

b) The depreciation amounts for each year of the deferred rebasing term – this is based on the proposed new depreciation study and methodology. By the end of 2028, Enbridge Gas will have amortized a total amount of $62 million with a remaining amount of $19 million to be amortized from 2029 to 2032. The remainder is written off upon the asset being retired.

	2024	**2025**	**2026**	**2027**	**2028**
Depreciation	16	15	14	12	6