ENBRIDGE

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February 12, 2026

VIA RESS AND EMAIL

Ritchie Murray
Acting Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ritchie Murray:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2025-0155
2024 Utility Earnings and Disposition of Deferral & Variance Account Balances – Interrogatory Responses

In accordance with the OEB's Procedural Order No. 1 dated December 18, 2025, enclosed please find the interrogatory responses of Enbridge Gas.

In accordance with the OEB's Practice Direction on Confidential Filings, Enbridge Gas is requesting confidential treatment of the following information. Details of the specific confidential information for which confidential treatment is sought are set out below:

Exhibit	Brief Description	Basis for Confidentiality
I.STAFF-9	CFR credits and value of credits	Enbridge Gas considers the number of CFR credits and value of credits obtained as confidential market sensitive information. This information fits in with items a) (i) - (iii) and b) in the OEB's Considerations in Determining Requests for Confidentiality.[1] This is also information that the OEB has indicated will be presumptively considered to be confidential – unit pricing of a third party.[2]

[1] Appendix A to the OEB's Practice Direction of Confidential Filings.
[2] This is noted as Item #1 in the "Categories of Information that Will Presumptively Be Considered Confidential", as found at Appendix B in the OEB's Practice Direction on Confidential Filings

Enbridge Gas received additional interrogatories filed confidentially from the Federation of Rental Housing Providers (FRPO) with the OEB. Although the interrogatories relate to Exhibit D, Tab 2, Schedule 2, which was filed confidentially with the OEB, a request for confidential treatment of the interrogatories and responses is not required.

Enbridge Gas would like to inform the OEB and parties that the responses to those interrogatories will be filed under separate cover.

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

Sincerely,

Richard Wathy

Richard Wathy
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)
EB-2025-0155 Intervenors

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, UFG Volume Variance Account

Actual UFG volumes for 2024 were 334,888 103m3. The variance between actual and forecasted UFG volumes of 91,206 103m3 resulted in a debit balance of $6.4 million in the UFGVVA, plus interest.

Enbridge Gas stated that the higher UFG volumes in 2024 are partially attributed to the harmonization of methodology for recording differences between estimated and actual UFG. As a result, Union rate zone UFG for 2024 includes adjustments for both December 2023 and December 2024 unbilled/nobill estimates:

- December 2023 adjustment: 21,049 10^3m^3
- December 2024 adjustment: 63,948 10^3m^3

Under the previous Union methodology, the 63,948 10^3m^3 would have carried into 2025.

Question(s):

a) Please provide a breakdown of the 2024 actual UFG into non-emissions-related, emissions-related and unexplained components (in 10^3m^3 and dollars).

b) Does Enbridge Gas expect actual 2025 UFG volumes to return to typical levels following the methodology harmonization? If not, please explain why not.

c) Other than the methodology harmonization, please discuss any other potential factors that contributed to the 2024 UFG variance.

d) Please reconcile the December 2023 and December 2024 adjustments noted above with the figures provided at Exhibit C, Tab 2, Schedule 3, Attachment 1.

<u>Response:</u>

a) and c)

Table 1 presents best estimates as of the time of filing of the volumetric impacts of known contributing sources of 2024 Unaccounted for Gas (UFG) that have been investigated. Enbridge Gas has identified nearly 50% of contributing sources of UFG impacting 2024.

It should be noted that contributing factors are often highly correlated with one another and the contributing factors outlined in Table 1 have a relative range of uncertainty associated with estimated volumetric impacts.

True-ups and accounting adjustments related to the estimation used in both the billing and accounting processes will continue to impact the UFG volumes estimated in Table 1. As the true-ups and adjustments are completed, Enbridge Gas expects the remaining Unexplained UFG Volumes associated with 2024 will be reduced.[1]

Enbridge Gas has included estimates for Gate Station Measurement Variation and Residential Meter Variation at lines 7 and 10 of Table 1 as these are known and accepted contributing sources of UFG, using the same methodology applied by ScottMadden in its Report on Unaccounted for Gas.[2]

While fugitive emissions-related volumes are presented separately in Table 1 per the request, fugitive emissions and UFG cannot be treated as interchangeable and increases in UFG should not automatically be assumed to result from increases in fugitive emissions, given that this is only one contributing factor. For the purposes of a best representative estimate, fugitive emissions included in Table 1 are based on the company's Fugitive Emissions Inventory.

Enbridge Gas will continue to investigate the Unexplained UFG volumes.

[1] See volumes set out in lines 1-4 of Table 1.
[2] Estimates for measurement variation are based on the proration identified in the ScottMadden Report on Unaccounted for Gas at EB-2019-0194, Report on UFG, December 19, 2019, pp.6-7. https://www.rds.oeb.ca/CMWebDrawer/Record/664529/File/document.

Table 1
2024 UFG Contributing Sources

Line No.	Particulars	Notes	2024
	Non-Emissions Related Investigation Estimates		
1	Gas Accounting Adjustments		(3,113)
2	Other Prior Period Billing Adjustments	(1)	7,113
3	Unbilled Estimates	(2)	46,438
4	No-Bills Estimates	(3)	(25,389)
5	Storage Inventory Audits and Adjustments		8,763
6	Minimum Linepack		980
7	Gate Station Measurement Variation		80,441
8	Residential Meter Variation		48,235
9	Total Non-Emissions Related Investigation Estimates	(4)	163,468
	Emissions Related Estimates		
10	Fugitive Emissions Inventory Estimated Volumes	(5)	23,039
11	Total Emissions Related Estimates		23,039
12	Enbridge Gas Total Annual UFG Volumes	(6)	372,399
13	Unexplained UFG Volumes for Investigation	(7)	185,892

Notes:

(1) Prior period billing adjustments relating to an applied year/month in a previous fiscal year unrelated to No-Bills
and Unbilled estimates.
(2) Impact from Harmonization of LUG Unbilled methodology only.
(3) Impact from Harmonization of LUG No-bills methodology only.
(4) Calculated as the sum of lines 1-8.
(5) Fugitive volumes, as related to the fugitive emissions reported to the provincial and federal GHG reporting programs, that result from the unintended releases of gases from equipment leaks and third-party damage events.
(6) Total unregulated and regulated UFG volume.
(7) Calculated as the difference between line 12 and the sum of lines 11 + 9.

b) No, Enbridge Gas does not necessarily expect UFG levels to return to historical levels following the methodology harmonization.

As it relates specifically to the harmonization of the methodology for recording differences between estimated and actual UFG, December 2024 unbilled and no-bill estimates relative to actual consumption had an impact on reported UFG in 2024 of 63,948 10^3m^3. Under the previous methodology, this impact would have been reported in 2025. Unbilled and no-billed estimates do not create incremental UFG, but the change in methodology resulted in a change to when that impact was reported. To that extent, the harmonization is not expected to contribute to a UFG variance going forward.

However, the contributing factors discussed in part a) all contribute to UFG in different ways based on the point in time nature of UFG reporting. As such, Enbridge Gas does not necessarily expect UFG levels to return to historical levels.

d) The December 2023 and December 2024 adjustments noted above are included in Line 4 “Total Actual UFG” in Exhibit C, Tab 2, Schedule 3, Attachment 1 and allocated across all twelve months of 2024. The adjustments are not explicitly presented in Exhibit C, Tab 2, Schedule 3, Attachment 1 in a specific month, given the requirement detailed in the Accounting Order for the UFGVVA to allocate the UFG annual volume variance monthly in proportion to actual sales volumes: “The UFG annual volume variance will be allocated monthly in proportion to actual sales volumes and be costed at the monthly approved weighted average reference price”[3].

[3] EB-2022-0200, Draft Rate Order, March 15, 2024, Appendix C, p.23.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 5, pg. 1, Deferral Clearance Variance Account

Enbridge Gas stated that the balance in this variance account includes the residual amounts not disposed of from the 2024 Rebasing Phase 1 Decision approved deferral balance for disposition cleared between April 1, 2024 to December 31, 2024. Enbridge Gas stated that the accrued interest of $5.041 million is almost entirely related to the large 2024 Rebasing Phase 1 Decision approval and drawdown of the balance over the April to December timeframe.

Question(s):

OEB staff notes that the disposition was approved for clearance between May 1, 2024 to December 31, 2024. Please clarify.

Response:

Enbridge Gas notes the incorrect date range provided in the evidence. OEB staff is correct that the disposition was approved for and occurred between May 1, 2024 and December 31, 2024. The variance account balance disclosed in evidence was calculated based on the correct date range and was unaffected by this wording mistake.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 6, pp. 2-3, Parkway Delivery Obligation Variance Account
The $3.246 million debit balance in this deferral account represents the difference between the OEB-approved PDCI cost of $14.150 million recovered in rates and the actual PDCI cost of $17.395 million. Enbridge Gas stated that the higher PDCI cost is primarily attributed to higher actual PDCI volumes than the forecast PDCI volumes of 79 PJ.

Enbridge Gas stated that it was not able to shift any PDO volumes in 2024 and that it did not identify practical market-based solution alternatives to reduce the PDO in 2024.

Question(s):

a) Please provide the underlying calculations for the actual PDCI cost of $17.395 million.

b) Please explain the factors that caused PDCI volumes to exceed the forecast of 79 PJ.

c) Please explain why Enbridge Gas was not able to shift any PDO in 2024.

d) Please provide market-based solutions that could be used to shift PDO volumes and why they were not practical for 2024?

Response:

a) Please see Table 1 for the calculations supporting the actual PDCI costs of $17.395 million:

Table 1
2024 Actual Parkway Delivery Commitment Incentive (PDCI) Costs

Line No.	Particulars	Jan - Apr (a)	May - Dec (b)	Total (c) = (a) + (b)
1	Parkway Delivery Volumes (TJs)	30,926	62,798	93,724
2	PDCI Rate (1)(2)	0.199	0.162	0.174
3	Actual PDCI Cost ($millions) (line 1 x line 2)	6.154	10.173	16.328
4	Market Based Solution - Firm Shift Exchange ($millions) (3)	0.356	0.712	1.067
5	Total Actual PDCI Cost ($millions) (line 3 + line 4)	6.510	10.885	17.395

Notes:

(1) Jan - Apr per EB-2022-0133, Decision on Settlement Proposal and Rate Order, November 3, 2022, Exhibit N1, Tab 1, Schedule 1, Appendix B, p.237, line 27.

(2) May-Dec per EB-2022-0200, Rate Order, Working Papers, Schedule 21, p.7, line 168, Updated March 15, 2024.+ EB-2022-0200, Rate Order, Working Papers, Schedule 26, p.10, column (c), line 135, Updated March 15, 2024.

(3) EB-2022-0133, Exhibit B, Tab 1, Schedule 1, p.11, Section 1.6.

b) PDCI increased as a result of increased demand in the Union South rate zone, which increased obligated deliveries at Parkway, and subsequently the PDCI paid for the obligated deliveries at Parkway.

c) In 2024, Enbridge Gas became aware of an operational restriction on its Dawn to Parkway system. In the near-term, incremental shifts of PDO from Parkway to Dawn were not considered.

d) Enbridge Gas did not issue an RFP for an exchange from Parkway to Dawn, or Kirkwall to Dawn in 2024 or 2025 as indications from the market were that it would not have been economical.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 8, pp. 4-5, Facility Carbon Charge Variance Account

Enbridge Gas stated that the $3.39 million related to Emissions Performance Standards (EPS) volumes is based on the company satisfying its full 2024 EPS compliance obligation by paying the excess emissions charge of $80/tCO_2e$. Enbridge Gas also noted that, since the deadline to meet the 2024 EPS compliance obligation is December 1, 2025, it retains the option to satisfy this obligation by purchasing Emission Performance Units (EPUs) from other EPS participants.

Enbridge Gas further stated that, should its 2024 EPS compliance obligation differ from the amount presented in evidence due to procuring EPUs at a price lower than the excess emissions charge, any resulting variances will be recorded in the 2025 Facility Carbon Charge Variance Account (FCCVA). Enbridge Gas also indicated that it will apply the evaluation criteria outlined in response at Exhibit I.STAFF2 of the 2025 FCPP Application to determine the appropriate balance between procuring EPUs and paying the excess emissions charge.

Question(s):

a) Given that the December 1, 2025, deadline for meeting the 2024 EPS compliance obligation has passed, please confirm how Enbridge Gas satisfied its 2024 EPS obligation:

    i. Did Enbridge Gas purchase EPUs from other EPS participants, or did it pay the excess emissions charge of $80/tCO_2e$?

    ii. If EPUs were purchased, provide details on the quantity procured, the purchase price, and how this affected the total 2024 EPS compliance cost compared to the $3.39 million outlined in evidence.

    iii. If the excess emissions charge was paid instead, please confirm that the obligation was met as originally stated.

Response:

a) i to iii) Enbridge Gas was unable to procure EPUs from other EPS participants, and as a result fulfilled its obligation through payment of excess emission units at \$80/tCO2e, and met its obligation as stated.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 9, pp. 1-6, Customer Carbon Charge Variance Account
Exhibit F, Tab 2, Schedule 4
Exhibit F, Tab 3, Schedule 4

The Customer Carbon Charge Variance Account (CCCVA) credit balance of $10.98 million plus $1.79 million in interest consists of:

- A cumulative CCCVA credit balance from 2022 to 2024 of $0.04 million plus $0.01 million in interest to ratepayers subject to the Federal Carbon Charge
- A Z-factor and base rate adjustment for the working cash impacts of setting the Federal Carbon Charge to zero as part of the 2026 rates application settlement agreement, totaling a credit to ratepayers of $10.94 million plus interest of $1.78 million

At Exhibit F, Tab 2, Schedule 4 and Exhibit F, Tab 3, Schedule 4, Enbridge Gas presents the Federal Carbon as a separate line item and provides the bill impacts resulting from the application with and without the Federal Carbon adjustment.

Question(s):

a) Please confirm whether Enbridge Gas intends to keep the CCCVA open solely for the purpose of capturing variances related to the removal and wind-down of the Federal Carbon Charge. For example, this would include adjustments from invoice corrections or rebilling for periods when the Federal Carbon Charge was in effect, which the Company remains obligated to report and remit to the Government of Canada.

b) How does Enbridge Gas plan to present this adjustment on customer bills and customer notices at the time of disposition?

Response:

a) Yes, Enbridge Gas intends to keep the CCCVA open to facilitate potential billing adjustments for the periods where the Federal Carbon Charge was in effect.

b) The disposition of 2024 deferral and variance accounts will be shown on customers' bills as a single rate adjustment line item comprised of the applicable unit rates multiplied by the customer's actual 2024 volume.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 10, Carbon Charges Bad Debt Deferral Account

Enbridge Gas is requesting to dispose of $11.72 million, plus $0.78 million in interest in CCBDDA.

In its 2024 Federal Carbon Pricing Program Application, Enbridge Gas forecasted it would incur $8.8 million incremental bad debt expenses in 2024 based on forecasted costs recoverable from customers as a result of the GGPPA and EPS Regulation.

Question(s):

a) Please identify and explain the drivers that caused actual 2024 bad debt to exceed the forecast by approximately 33%.

Response:

a) Two factors contributed to the 2024 carbon related bad debt being higher than the forecasted amount. The first and main contributing factor to the variance was due to the higher than forecasted levels of 2024 Company bad debt ($38.5 million actual compared to $31.0 million forecasted). The second factor contributing to the variance in carbon related bad debt is due to a slightly higher than forecasted percent allocation of carbon related bad debt (30.4% actual compared to 28.4% forecasted). As shown in Exhibit I.CCC-2 part a), the percentage of carbon related bad debt is derived by dividing 2024 actual carbon revenues by 2024 actual Company revenues (including carbon revenues).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 11, pp. 4-5, Integrated Resource Planning Operating Costs Deferral Account
Exhibit C, Tab 2, Schedule 20, pg. 3
EB-2022-0335, Decision and Order, March 27, 2025

Enbridge Gas proposed to recover $0.16 million in the IRP Operating Costs Deferral Account incurred in 2023 and 2024 related to the IRP Pilot Projects application, in advance of the OEB's Decision and Order on this application that was provided on March 27, 2025. Enbridge Gas does not propose to recover capital costs related to meter installation in the (cancelled) Parry Sound IRP pilot through the IRP Capital Costs Deferral Account. Enbridge Gas noted that these meters are still being utilized, and Enbridge Gas will consider the expenditures as part of typical meter exchange/replacement activity.

Question(s):

a) Please provide the capital costs that were recorded associated with meter installation in Parry Sound.

b) Does Enbridge Gas's proposed approach mean that these costs are included in Enbridge Gas's 2024 capital budget?

c) Please describe how these meters are being utilized given that the Parry Sound pilot was cancelled.

d) Please provide Enbridge Gas's rationale as to why costs associated with the cancelled Parry Sound Pilot project should be eligible for recovery, both with regards to the costs proposed for recovery through the IRP Operating Costs Deferral Account, and the capital costs associated with meter installation in Parry Sound.

e) The overall budget for the IRP Pilot Project as described in the IRP Pilot Project application was $14.2 million. Please confirm if the 2023 and 2024 costs proposed for recovery through the IRP Operating Costs Deferral Account will be counted towards this overall IRP Pilot Project budget.

Response:

a) The total capital cost that was recorded associated with meter installation in Parry Sound is $14,607.

b) Enbridge Gas's approach means that the capitalized costs of the in-service meters form part of 2024 capital spend and rate base. This is appropriate as while the pilot did not proceed, the benefit of the meter exchange was still received and will be realized over the life of the asset, and as such, it is appropriate to recover the amount consistent with regular meter exchange capital spending, over the life of the asset. Note, however, that Enbridge Gas is not proposing to recover the associated revenue requirement for 2024 in the IRP Capital Costs Deferral Account as the amount is immaterial.

c) As part of the Parry Sound pilot project, existing residential customer meters were replaced with meters equipped with an Encoder Receiver Transmitter (ERT) module to allow for collection of hourly data. While the ERT function of the meter is not being utilized, the meter itself is still utilized as the customer's meter.

d) Costs associated with the cancelled Parry Sound Pilot Project should be eligible for recovery as these costs were prudently incurred to support the development of the pilot project at the time and the O&M costs are incremental to Enbridge Gas's 2024 approved rates. As noted in part b), Enbridge Gas is not seeking recovery of the associated revenue requirement of the capital costs incurred for the Parry Sound Pilot Project.

e) The $14.2 million described in the IRP Pilot Project application reflects the costs associated with the Southern Lake Huron Pilot Project, inclusive of costs incurred in 2023 and 2024. These costs will be counted towards this overall IRP Pilot Project budget. The costs incurred for Parry Sound in 2023 ($0.026 million) and 2024 ($0.021 million) were not included in the $14.2 million as the Parry Sound Pilot Project was withdrawn from the updated IRP Pilot Project application and therefore the Parry Sound Pilot Project costs will not be counted towards that budget. The amended application outlined that costs related to the development of the Parry Sound Pilot Project would be recorded in the IRP Operating Costs Deferral Account, and that Enbridge Gas would bring forward actual balances in the Non-Commodity Deferral Account Clearance application.[1]

[1] EB-2022-0335, Exhibit E, Tab 1, Schedule 2, pp.1-2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 12, pg. 1, Dawn Parkway Surplus Capacity Deferral Account
In 2024, Enbridge Gas recognized $0.9 million of revenue from the sale of surplus capacity.

Question(s):

a) Please confirm whether Enbridge Gas evaluated this surplus capacity for potential PDO reduction prior to offering it for sale. Please explain.

Response:

Please see the response at Exhibit I.STAFF-3 part c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 15, Clean Fuel Regulation Credits Deferral Account

The purpose of the CFR Credits Deferral Account is to record the revenues obtained by Enbridge Gas from the sale of CFR credits, net of any incremental offsetting credit formation, certification and transaction administration costs.

In 2024, Enbridge Gas created credits under the CFR from its compressed natural gas (CNG) vehicle activities during the 2023 compliance period. Enbridge Gas sold the credits in 2024 and recorded the revenue from the sale in the CFR Credits Deferral Account, as a payable of $0.056 million, plus interest.

Question(s):

Please provide the total number and value of CFR credits sold in 2024, the incremental costs incurred and a reconciliation showing how these amounts result in the net balance recorded in the deferral account.

Response:

In accordance with OEB Practice Direction on Confidential Filings, Appendix A, clauses (a(i)) to (a(iii)), clause (b) and Appendix B, bullet 1, Enbridge Gas considers the number of CFR credits and value of credits obtained as confidential market sensitive information. Enbridge Gas did not incur incremental costs in relation to what is already included in rates to create or sell 2023 CFR credits in 2024.

CFR Revenues	[redacted]
Administrative cost recovered[1]	[redacted]
Net revenue	= $55,642

[1] Administrative costs are recovered from Enbridge Gas owned CNG rental station customers who request CFR credit creation and sales support.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 16, pg. 1, Indigenous Working Group Deferral Account
Exhibit G, Tab 3, Schedule 1, pg. 8, Indigenous Working Group Report

The balance in the Indigenous Working Group Deferral Account for 2024 is a debit of $0.119 million plus forecast interest of $0.007 million. Table 1 outlines the amounts by Indigenous Working Group participant.

Table 1
IWG Incremental Capacity Funding

Line No.	Participant	Amount ($000s)
1	Resilient LLP	$ 64.3
2	Mississaugas of Scugog Island	22.2
3	Woodward and Co	16.5
4	Three Fires Group	11.2
5	Chippewas of the Thames	5.2
6	Total	$ 119.3

Enbridge Gas stated that the capacity funding costs of the Indigenous Working Group over its first full year of operation are likely not representative of the reasonable ongoing costs that will be necessary to participate in and support the IWG, as a significant portion of the expenses incurred during 2024 were invoiced in 2025.

Question(s):

a) Please confirm whether the Indigenous Working Group Deferral Account balance reflects activity from September 2023 to December 2024. If so, please identify the portion of the balance attributable to 2023 activity.

b) OEB staff notes that some law firms represent multiple Indigenous Working Group participants. Please confirm whether they bill separately for each client's participation and explain how these costs are allocated.

c) Please quantify the amount of 2024 work that was invoiced in 2025 and reconcile it with the 2024 Indigenous Working Group Deferral Account balance. Other than the invoice timing, please provide further rationale for why 2024 spending was significantly lower than the approved 2024 budget.

d) Please provide the estimated Indigenous Working Group spending for 2025.

Response:

a) Yes, the Indigenous Working Group (IWG) Deferrals Account balance reflects activity from September 2023 to December 2024. The portion attributable to 2023 is $41,045. Please see Table 1.

b) Confirmed. The law firms bill separately for each client's participation. The law firms bills are generally split equally between the two main Indigenous clients they represent, with certain of the clients occasionally requiring a higher allocation depending on additional calls or meetings or taking the lead on one aspect of drafting.

c) Please see the reconciliation of balances in Table 1:

Table 1
Reconciliation of 2024 Indigenous Working Group Invoices and Balances

Line No.	Particulars	Amount ($000s)
1	2023 Invoices processed and included in 2024 balance	41.0
2	2024 Invoices processed and included in 2024 balance	78.3
3	Subtotal – 2024 IWG Deferral Balance	119.3
4	2024 Invoices processed and included in 2025 balance	128.5
5	Subtotal – 2024 Invoices (not including 2023)	206.8

The amount of 2024 work that was invoiced in 2025 was approx. $128 thousand. This included invoices from Brattle Group and the IWG membership that were received in December 2024 but did not get processed until January 2025. Enbridge Gas proposes to include these in the 2025 balance and bring this balance forward in the 2025 Deferrals application. The 2024 spend was lower than the approved 2024 budget as we did not see an increase in participation from additional First Nations and their respective consultants, their legal support or experts.

d) Enbridge Gas is still in the process of finalizing IWG spend related to 2025 actual work completed and will be filing it within the 2025 Deferrals application with supporting evidence. The current estimate of 2025 invoiced costs is approx. $137 thousand. The IWG did not retain new experts in 2025, which would account for the lower spend. In 2026, the IWG have retained two experts to examine rebasing and rates for First Nations customers. The budget proposed for the new experts is included within the 2026 budget.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit G, Tab 3, Schedule 1, pg. 8, Indigenous Working Group Report

Enbridge Gas filed an Indigenous Working Group Report summarizing the activities of the working group and initiatives planned or implemented, including meeting minutes. As part of its report, the Indigenous Working Group presented an estimated 2026 budget of $800,000 for the OEB's review. This includes $295,000 for legal support, $255,000 for consultants and First Nation representatives and $250,000 for experts. OEB staff notes that these amounts represent increases of $55,000 (23%), $105,000 (70%) and $0, respectively, compared to the 2024 budget.

Question(s):

a) Based on the attendance lists for 2024 and 2025 meetings, there does not appear to be increased participation over time. Please explain the rationale for the proposed 70% increase in the budget for consultants and First Nation representatives and how Enbridge Gas plans to use this additional funding to support the participation of First Nation rightsholders rather than consultants.

b) For each spending category (legal support, consultants and First Nations representatives, experts), please explain how the proposed amounts were developed, what activities they are intended to support, and provide justification for the proposed amounts.

c) Please compare the proposed 2026 amounts for legal support, consultants and First Nation representatives and experts with the actual costs incurred in 2024 and 2025. Please explain any major variations.

Response:

a) The 2024 Indigenous Working Group (IWG) budget was established by the parties as part of the 2024 Rebasing Phase 1[1] settlement proposal. The OEB issued the Decision on Settlement Proposal (Decision on Settlement Proposal) on August 17,

[1] EB-2022-0200.

2023. The first meeting of the IWG was held on September 18, 2023 and the estimated budget for capacity funding to the end of 2024 consisted of a total of $640,000. The budget was an estimate based upon assumptions about how many Indigenous Parties might choose to participate in the IWG and the topics that would be explored. It was clear in the OEB's Decision on Settlement Proposal that actual costs might vary. The increase to the budget for consultants and First Nation representatives was to allow for additional participation by First Nations, other than the intervenor groups of Ginoogaming First Nation and Three Fires Group, as the IWG became more established and known to other interested First Nation community or reserve that is an Enbridge Gas customer or whose distribution company is an Enbridge Gas customer. Since starting, the IWG has added Chippewas of the Thames, Mississaugas of Scugog Island/Minogi Corp and Six Nations Natural Gas to the group. While we have not yet seen significant growth in First Nations rightsholder representatives at the IWG just yet, the group is still establishing itself.

b) Further to the response at Exhibit I.STAFF-11 part a), the 2024 budget was an estimate provided by the Settlement parties based upon assumptions about how many Indigenous Parties might choose to participate in the IWG and the topics that might be explored. Each 2024 spending category ($240,000 for legal support; $150,000 for general consultants and $250,000 for expert analysis and support) was agreed to by the parties based on reasonable estimates for the necessary expertise. In order for the Indigenous Parties to meaningfully participate in the IWG, the parties agreed that the estimated funding would provide support for First Nation legal representatives from TFG, Minogi and Ginoogaming First Nation to prepare for, attend and participate in the IWG meetings and focus groups, facilitate discussion amongst the IWG membership, and consider the appropriateness of experts to assist in providing advice to Indigenous Parties on specific issues of importance to the IWG and, if agreed to by Enbridge Gas, to engage with experts, on behalf of their clients.

The capacity funding category for general consultants and First Nations participation is intended to cover the costs for First Nation representatives, Six Nations Natural Gas and the Economic Development group representatives to prepare for, attend and participate in IWG meetings, including IWG subcommittees or meetings among the Indigenous Parties.

Experts are being used by the IWG to provide Enbridge Gas with information on topics of interest to the Indigenous Parties so these Parties can more meaningfully participate and engage in Enbridge Gas matters within the scope of the IWG, such as the Phase 1 review of the Pathways document, examination into a different rate for First Nations customers and the 2029 Rebasing Indigenous Engagement process.

c) The proposed 2026 IWG budget is $295,000 for legal support; $255,000 for consultants and First Nation representatives; and $250,000 for experts. The budget proposed for 2026, which is significantly higher than the costs incurred for 2024 & 2025, is to ensure that there are adequate funds available for the IWG to address topics of interest, welcome new membership should there be an interest and ensure funds are available to hire new experts to address topics such as rate harmonization, 2029 Rebasing, among other topics of interest to the Indigenous Parties.

   Please refer to Exhibit I.STAFF-10 for 2024 & 2025 costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 18, Getting Ontario Connected Act Variance Account

The table below outlines Enbridge Gas's 2024 GOCA balance calculation.

Table 3
2024 Base Rate Budget vs. Actuals

Line No.	Particulars ($ millions)	Amount
1	2024 Base Rate Locate Budget	51.1
2	2024 Locate Actuals	66.0
3	2024 GOCA Variance Balance	14.9

Enbridge Gas stated that the $14.892 million recorded in excess of the approved budget is not due to inflationary or volume-related factors but is directly and solely attributable to structural changes in the locate industry driven by Bill 93.

The average cost per locate increased to $67 in both 2023 and 2024, representing increases of 109% and 108% respectively, compared to the 2021 average cost.

Question(s):

a) Please explain how Enbridge Gas differentiates between incremental locate costs that are directly attributable to Bill 93 from those that are not. Does Enbridge Gas assume that any variance between 2024 locate actuals and the 2024 base rate locate budget is solely caused by Bill 93?

b) Does Enbridge Gas expect the average cost per locate to stabilize at approximately $67 in future years? If not, please explain why not.

c) Please clarify what portion of the 108% increase is attributable to the incremental staffing that was required in 2023 to meet the new 5-day mandate. Did Enbridge Gas onboard additional LSPs in 2024? If so, please explain why.

<u>Response:</u>

a) As stated in evidence, the 2024 base budget, which was prepared in early to mid-2022, incorporated allowances for typical cost drivers—such as inflation, typical wage increases, and general market pressures—as well as an increase for anticipated, but then-unknown, Bill 93 related impacts. The resulting 2024 budget reflected a 28% increase over 2022 actual locating costs, a notable escalation considering the historically flat trend in annual locating spend from 2019 to 2021. In the Company's view, the remaining variance is solely caused by Bill 93. Please see Exhibit C, Tab 2, Schedule 18, pages 2 to 4.

b) Enbridge Gas is not currently aware of any drivers within the locate environment that would indicate any drastic changes to cost per locate, apart from any unforeseen change in policy, labour union agreements, unexpected RFP outcomes etc.

c) The various Locate Service Providers (LSPs) manage business items such as staffing levels. Enbridge Gas pays unit pricing as per contractual agreements. Enbridge Gas did not onboard additional LSPs in 2024 as the existing LSPs were able to staff adequately under the current contract requirements.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 19, Enbridge Sustain Affiliate Recoveries Variance Account
During 2024, Enbridge Sustain received services at a total cost of $1.1 million. As such, when compared to the $1.0 million base rate adjustment for 2024, Enbridge Gas recorded in the Enbridge Sustain Affiliate Recoveries Variance Account a credit to customers (or payable) of $0.091 million, plus interest.

Question(s):

a) Please confirm that all transactions between Enbridge Gas and Enbridge Sustain in 2024 were conducted in compliance with the Affiliate Relationships Code for Gas Utilities (ARC).

Response:

a) Confirmed. Please see Exhibit C, Tab 2, Schedule 19, paragraph 3:

> As noted in Phase 2 of the 2024 Rebasing Application, while (during 2024) Enbridge Sustain was operated as a line of business within Enbridge Gas (up until September 30, 2024), it was treated as though it was an affiliate and costs were charged to Enbridge Sustain on a fully allocated basis, consistent with the requirements of the Affiliate Relationships Code for Gas Utilities (ARC). This process continued on after Enbridge Sustain became an affiliate (Enbridge Sustain Inc.) of Enbridge Gas as of October 1, 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, Unabsorbed Demand Costs (UDC) Variance Account-Union Rate Zones
The actual unutilized capacity in 2024 was 51.7 PJ. Enbridge Gas stated that the level of unutilized capacity experienced in 2024 was largely due to planned unutilized capacity (and resulting UDC), warmer than normal temperatures and lower customer use.

Question(s):

a) Does Enbridge Gas anticipate that UDC levels will continue to increase in future years? If so, please describe the factors driving this trend and the measures Enbridge Gas intends to implement to mitigate higher UDC levels.

b) Please describe the actions Enbridge Gas undertook in 2024 to minimize unutilized capacity and the resulting UDC costs.

Response:

a) No, as detailed in the Company's 5-Year Gas Supply Plan,[1] planned unutilized capacity levels for the 2025/26 to 2029/30 gas years are lower than what was experienced in 2024.

b) Throughout 2024, Enbridge Gas actively monitored actual weather impacts, storage inventory levels, and customer demand and adjusted gas supply purchases to achieve the lowest UDC possible while cost-effectively meeting customer demands. Specifically, Enbridge Gas actively managed its transportation portfolio to ensure that any pipeline capacity left unutilized resulted in the lowest possible overall cost(s) considering operational constraints, pipeline tolls, upstream natural gas supply costs, and the market value of associated pipeline capacity in the secondary market. Further, Enbridge Gas also released and sold unutilized upstream transportation

[1] EB-2025-0065, 5-Year Gas Supply Plan, Section 5.3, Table 7, p.45. Note that the values in Table 7 are in PJ not TJ.

capacity on the secondary market using competitive bidding processes involving multiple counterparties, and awarded the released capacity to the highest bid(s) offered (resulting in the greatest cost recovery value) to offset UDC costs incurred.[2]

Enbridge Gas managed the impacts of warmer than normal winter temperatures and lower customer use on end of winter 2023/24 storage inventory levels in-part by avoiding some degree of its planned 2024 summer supply purchases at Dawn since doing so did not affect UDC costs. Unfortunately, in 2024, there were insufficient planned summer supply purchases at Dawn to offset all excess storage inventory levels experienced. As a result, it was necessary to avoid additional planned supply purchases.

[2] EB-2025-0155, Exhibit E, Tab 1, Schedule 1, p.2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 8, pp. 3-5

Question(s):

a) Please provide the detailed calculation showing the allocation of the total $5.14 million facility-related obligation between the regulated and unregulated businesses.

b) Please explain how, on a final basis, Enbridge Gas met its 2024 EPS compliance obligation. If Enbridge Gas did end up purchasing EPUs (instead of meeting the entire obligation by paying the excess emission charge), please provide the final EPS compliance cost.

Response:

a) The calculation of regulated and unregulated facility-related obligation costs allocations is shown in Table 1. The company use carbon costs and Emissions Performance Standards (EPS) costs are based on the volumes of natural gas used in Enbridge Gas's operations, where the volumes of fuel used are reported according to regulated and unregulated (e.g. non-utility storage) business activities.

Table 1
2024 Summary of Facility-Related Costs

Line No	Particulars	Jan – Mar 2024	April – Dec 2024	Jan – Dec 2024
1	Company Use Volumes – regulated (10^3m^3)	5.88	6.68	12.56
2	Company Use volumes – unregulated (10^3m^3)	0.02	0.03	0.05
3	Federal Carbon Charge Rate ($\$/m^3$)	0.1239	0.1525	
4	Company Use Costs – regulated ($millions) (line 1 x line 3)	0.73	1.02	1.75
5	Company Use Costs – unregulated ($millions) (line 2 x line 3)	0.00	0.00	0.00
6	Company Use Costs – total ($millions) (line 4 + line 5)	0.73	1.02	1.75
7	EPS Compliance Obligation (tCO_{2e})			42,322
8	Excess Emissions Charge ($\$/tCO_{2e}$) (1)			80.00
9	EPS Compliance Obligation Costs – Total ($millions) (line 7 x line 8)			3.39
10	EPS Compliance Obligation Costs - Regulated ($millions)(2)			2.85
11	EPS Compliance Obligation Costs - Unregulated ($millions)			0.55
12	Total Facility Related Costs - Regulated ($millions) (line 4 + line 10)			4.59
13	Total Facility Related Costs - Unregulated ($millions) (line 5 + line 11)			0.55
14	Total Facility Related Costs ($millions) (line 12 + line 13)			5.14

Notes:
(1) Emissions Performance Standards Regulation, O.Reg. 241/19, Section 11.1
(2) Regulated EPS costs are allocated based on regulated/unregulated total EPS volumes (see Table 2)

Table 2
2024 Facility-Related EPS Volumes[1]

Line No.	Particulars	Actuals
1	EPS Volumes - Regulated (10^3m^3)	85,248
2	EPS Volumes - Unregulated (10^3m^3)	15,670
3	EPS Volumes (10^3m^3)	100,918

Notes:
(1) EPS volumes for January 1 to December 31, 2024.

b) Please see response at I.STAFF-4 part a) i to iii.

ENBRIDGE GAS INC.

Answer to Interrogatory from Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 10, p. 3

Question(s):

a) Please provide the detailed calculation supporting the 2024 carbon charge-related bad debt of $11.72 million.

Response:

a) Enbridge Gas has calculated the 2024 carbon charge-related bad debt according to the methodology provided in Exhibit I.VECC.7 of the 2022 FCPP Application[1]. Please see Table 1.

Table 1
2024 Carbon Charge Bad Debt

Line No.	Rate Zone	2024 FCPP Charges billed ($ million)	2024 Total Company Revenue (including FCPP charges) ($ millions)	2024 % of bill related to FCPP (%)	2024 Company Bad Debt ($ millions)	2024 Carbon Bad Debt ($ millions)
		(a)	(b)	(c) = (a / b)	(d)	(e) = (c * d)
1	EGD	1,300.9	4,188.7	31.1	15.4	4.80
2	UGL	775.2	2,586.5	30.0	23.1	6.92
3	EGI Total	2,076.1	6,775.2	30.4	38.5	11.72

[1] EB-2021-0209.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 11, pp. 1, 5

Question(s):

a) Please provide an excerpt from the 2024 rebasing proceeding that shows the base IRP O&M costs that are reflected in rates.

b) Please explain why Enbridge Gas believes that the 2024 costs ($0.1M) are incremental to the IRP-related costs in 2024 base rates.

Response:

a) Please see EB-2022-0200, Exhibit I.9.1-LPMA-47 part p), which states:

> With respect to the Integrated Resource Planning (IRP) Operating Costs Deferral Account, within the 2024 forecast of costs, Enbridge Gas has included $1.8 million in administrative costs related to incorporating IRP requirements into its business processes and requirements. No costs have been included in relation to approved IRP plans, as no plans have been approved to date. The Company would like to clarify that it is not seeking variance account treatment related to these ongoing administrative costs. The Company has proposed the continuation of the IRPOCDA in order to capture incremental operating, administrative, and evaluation costs that result from approved IRP plans, which were not able to be forecast, or incremental operating and administrative impacts that result from IRP rules/requirements/guidelines that may continue to change or evolve.

b) As noted in the IRP Pilot Project Application, the costs associated with the pilot project were not included in the forecast of operating costs supporting Enbridge Gas's 2024 Rebasing Phase 1 application[1].[2] Therefore, these costs are considered incremental to the costs that support Enbridge Gas's 2024 current approved interim rates, and applicable for clearance through the deferral account.

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[1] EB-2022-0220.
[2] EB-2022-0335, Exhibit E, Tab 1, Schedule 2, updated June 28, 2024, p.1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 12, pp. 1-2

Question(s):

a) Please explain what efforts Enbridge Gas made during 2024 to market/promote the sale of the available 89 TJs/d of Dawn to Parkway capacity.

b) Please advise whether the unit rate shown in Table 1 is the M12 Dawn to Parkway rate for 2024.

c) Please confirm that if the entirety of the surplus capacity was sold approx. $4.1M of revenues would have been recorded in the account for refund to ratepayers.

Response:

a) Enbridge Gas is in constant communication with the market to promote its services and, in 2024, sold some excess capacity in the market.

b) Yes, the unit rate shown in Table 1 is the M12 Dawn to Parkway rate for 2024.[1]

c) Confirmed.

[1] EB-2022-0200, Interim Rate Order, April 11, 2024, Appendix B, p.85.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 13, p. 2-3
Exhibit G, Tab 4, Schedule 1, p. 4

Question(s):

a) Please confirm that the total administrative costs associated with DIMP and EDIMP was approximately $0.73M (or 42%) higher than planned.

b) Please provide a detailed breakdown (e.g., FTE #, compensation costs, contractor costs, training, etc.) of the administrative cost increase (both DIMP and EDIMP) between planned and actual.

Response:

a) Confirmed. The total administrative costs associated with DIMP and EDIMP were approximately $0.73M (or approximately 42%) higher than originally planned. As described in Exhibit C, Tab 2, Schedule 13, page 3, paragraph 8, the variance is primarily attributed to an increase in employee and contract worker support allocated to the DIMP portfolio that was not in the original workplan. The additional support included efforts related to DIMP risk modeling developments, updating and creating required procedures, and management and reporting of inspections and assessments.

b) Refer to Table 1 below for a detailed breakdown.

Table 1
2024 DIMPVA Administrative Cost Breakdown

Line No.	Particulars	2024 Workplan ($000s)	2024 Actuals ($000s)	Variance ($000s)
	DIMP Admin			
1	FTE Costs	465	1,252	787
2	Contingent Worker (CWR) Costs	178	300	123
3	Employee Related Services (Training)	7	37	30
4	Professional Dues	2	2	1
5	Travel & Accommodation	44	11	(33)
6	Other Admi	3	(7)	(10)
7	DIMP Admin Total	699	1,596	897
	EDIMP Admin			
8	FTE Costs	737	743	6
9	Contingent Worker (CWR) Costs	310	108	(202)
10	Employee Related Services (Training)	2	20	18
11	Professional Dues	1	1	1
12	Travel & Accommodation	3	13	10
14	Other Admin	0	1	1
15	EDIMP Admin Total	1,053	887	(166)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 16, p. 1
Exhibit G, Tab 3, Schedule 1, pp. 6-8

Question(s):

a) Please provide the best available forecast of the 2025 IWG costs that will be proposed for recovery in the 2025 IWG account.

b) Please further explain the statement that additional funding will be required as: "there is a growing need to reflect the changing composition of representatives attending and supporting the IWG by amending the previous category of "consultants" to include First Nation representatives who are rightsholders and not consultants."

c) Please file the Brattle Group Report and Presentation referenced at Exhibit G, Tab 3, Schedule 1, p. 6.

Response:

a) This proceeding is with regards to the 2024 deferral account balances. The details of the 2025 Indigenous Working Group (IWG) cost will be provided within the 2025 Deferral Disposition application with supporting evidence.

b) The IWG composure has a number of different type of attendees including legal representatives, economic development corporation representatives (consultants), Six Nations Natural Gas representatives and a couple of representatives that work directly for the First Nation communities. The IWG is seeking to expand the composure of the representatives to ensure that there are more representatives from the First Nations communities themselves.

c) Please see Attachment 1 for the Brattle presentation provided to the IWG and Enbridge Gas.

Energy Transition Discussion

ENBRIDGE GAS INC AND INDIGENOUS WORKING GROUP

PRESENTED BY:

BRUCE TSUCHIDA

TOM CHAPMAN

PETER FRASER

DECEMBER 10, 2024

Brattle

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Summary

- First Nations' deep connection and reliance on their traditional lands means they are disproportionally impacted by climate change relative to other Enbridge Gas Inc. (EGI) consumers.
- At the same time the energy transition presents a generational opportunity to create a prosperous future by creating jobs, education and meaningful economic reconciliation.
- Within this context, Indigenous Working Group (IWG) members have been clear that EGI's current Energy Transition Plan does not meet their expectations:
  - Current scenarios do not explain how options will impact daily lives - not just natural gas for heating but also how options contribute to much needed economic and social development.
  - Current scenarios do not consider the full "lifecycle" impact to their traditional lands and habitats.
- While EGI alone cannot solve all First Nations' energy transition challenges, they can devote greater time and resources to address the issues raised by the IWG and improve the engagement process.
- The remainder of this report lays out next steps, issues and recommendations as well as the perspectives of IWG members developed though in-person and interactive engagement meetings.

Recommendations: **Energy Transition Plan**

ISSUE	RECOMMENDATIONS
EGI's pathway scenarios do not adequately explain impacts on First Nation communities' daily lives in ways that can be readily understood.	• EGI's Transition Plan should include details on how each scenario will impact land use and traditional activities. • Any plan (and future studies) should include the broader employment, business and social benefits that will allow First Nation communities to share in the future prosperity. • EGI's pathway scenarios need to be expanded to consider the "full lifecycle" of options including downstream and upstream economic and environmental impacts.
First Nation communities are under-resourced compared to EGI and need access to information and expertise to participate effectively in EGI's energy transition planning process.	• In moving from pathway scenarios to implementable plans, EGI will need to increase its support for First Nation communities to build sufficient human, financial, and technical capacity to plan their energy future.

Recommendations: **Commitment to Equality**

ISSUE	RECOMMENDATIONS
EGIs pathway scenarios pose economic, environmental and social risks for First Nation communities that will need to be managed.	• EGI to commit to developing mechanisms for Indigenous peoples to manage the inherent economic and social risks in its plans including affordability. • EGI to directly include the IWG in future integrated resource planning activities it may undertake.
Meaningful reconciliation is needed to ensure a successful energy transition.	• EGI plans should contain mechanisms that fairly compensate First Nation communities for historical and future land and resource use. • EGI should provide First Nation communities the opportunity to be equity partners and/or owners in future projects that use traditional lands and resources, consistent with industry best practice.

Recommendations: **IWG Process**

ISSUE	RECOMMENDATIONS
The current engagement process needs to recognize First Nation communities' close connection to the land that makes them more vulnerable to developments that impact their traditional lands and ways of life.	• EGI's engagement process should include in-person meetings with all impacted communities. • EGI should initiate engagement with First Nation communities at the creation of pathway scenarios and Energy Transition plans, not at the end of the process.
Expectations between IWG members and EGI need to be aligned, and communication improved.	• Develop a Terms of Reference for the IWG, setting out clear goals and objectives for the group. • Ensure appropriate EGI staff are available to answer IWG questions on EGI's pathway scenarios. • Meeting materials should be provided on an EGI hosted web page to ensure a public record of the engagement and ensure accessibility by First Nation communities who are not part of the IWG.

Suggested Next Steps (for 2025)

Tangible steps for EGI/IWG in 2025 based on the three recommendations (see slides 5 through 7) include:

Initiate a **second phase of pathway analysis** to assess the full environmental lifecyle of options and expected impacts on First Nation community daily lives.

- **Consult with IWG on scope in Q1 2025.**
- **EGI provide IWG with resources to jointly manage and participate in the assessment**
- **Complete studies by Q4 2025.**

Initiate work on **developing options on potential economic opportunities** and mechanisms to achieve mutually beneficial outcomes.

- **Establish an Economic Development forum to oversee the development of partnership opportunities.**
- **EGI to present models for economic participation by Q2 2025 and host workshop in Q3 2025.**

EGI needs to **address gaps in the current engagement approach** to ensure all voices are heard.

- **EGI, in partnership with the IWG, to conduct in-person engagement with all impacted First Nation communities on reserve or within reasonable distance to attend in person.**
- **EGI to host a webpage for engagement materials accessible for all First Nations by Q1 2025.**

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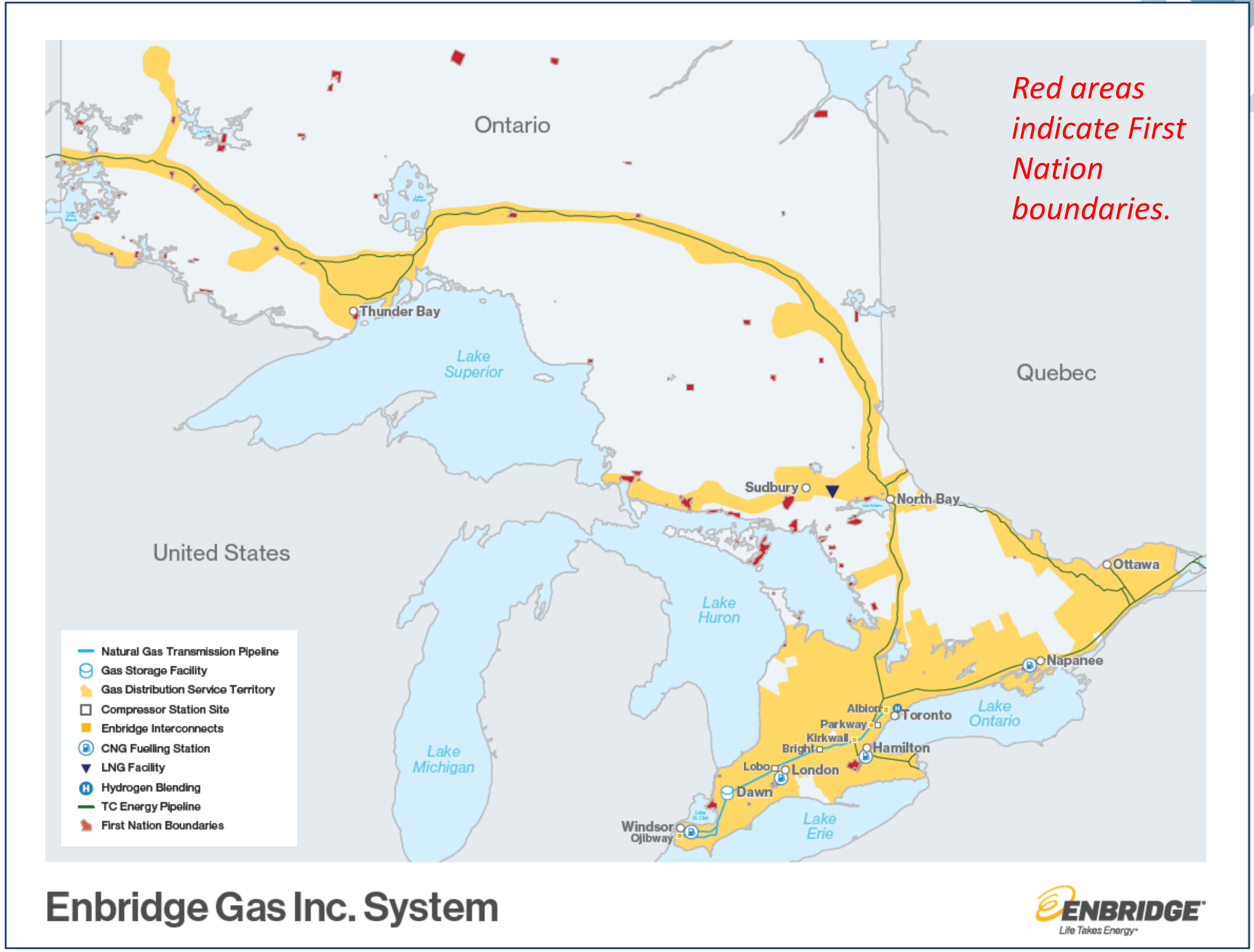
Filed: 2026-02-12, EB-2025-0155, Exhibit I.CCC-6, Attachment 1, Page 11 of 42

Enbridge Gas Inc. and the Indigenous Working Group (IWG)

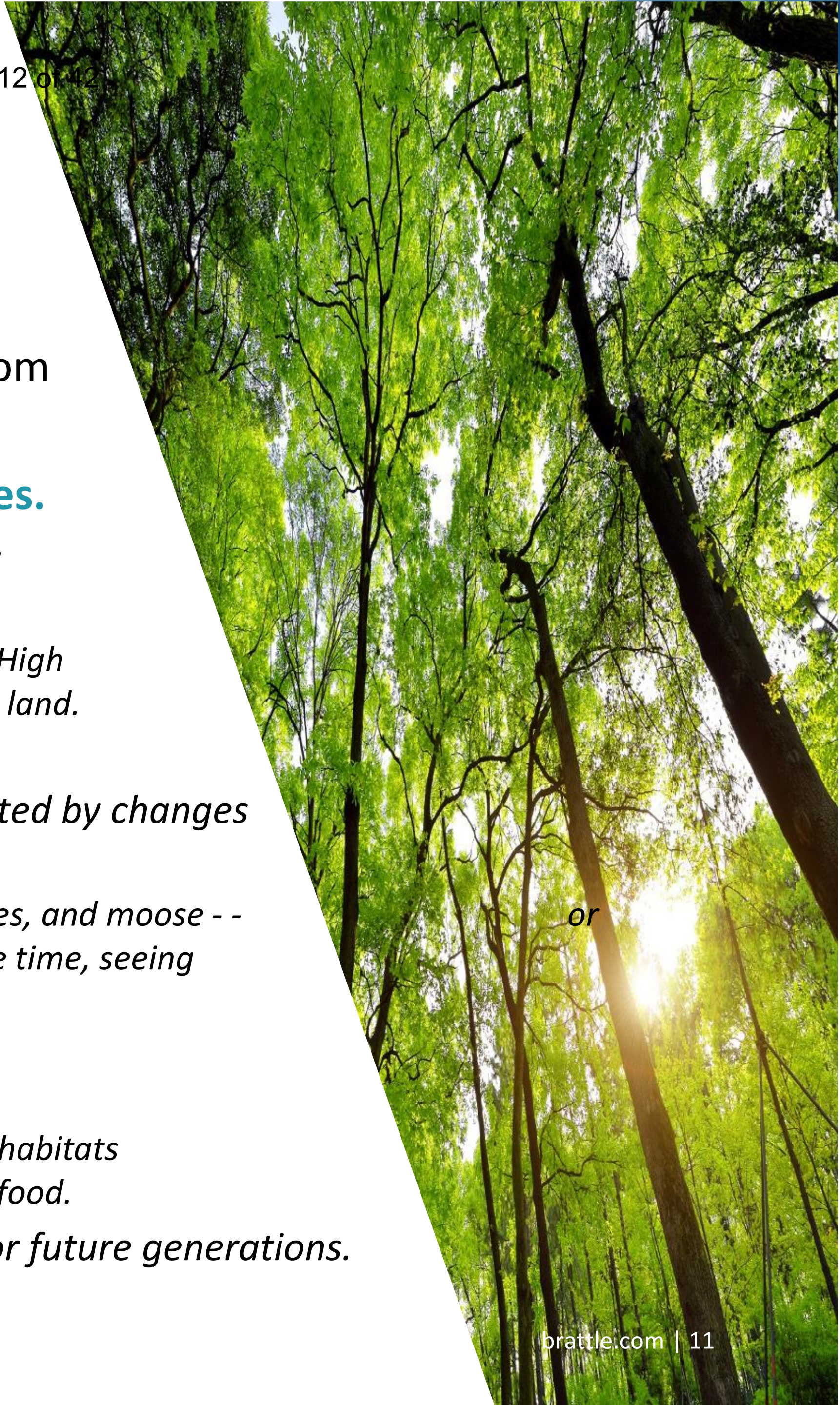
Who is involved?

- Enbridge Gas Inc. (EGI)
- The Indigenous Working Group (IWG) comprising of the Three Fires Group, Ginoogaming First Nation, Minogi Corp., Chippewas of the Thames First Nation, Six Nations Natural Gas, and other interested and eligible Indigenous participants.
- The Brattle Group (Brattle), a consulting firm with significant energy economics expertise and experience.
  - Brattle was asked to review and analyze EGI's pathway scenarios from the specific perspective of the impact such plans may produce for IWG members, and to provide feedback to EGI through the IWG process.



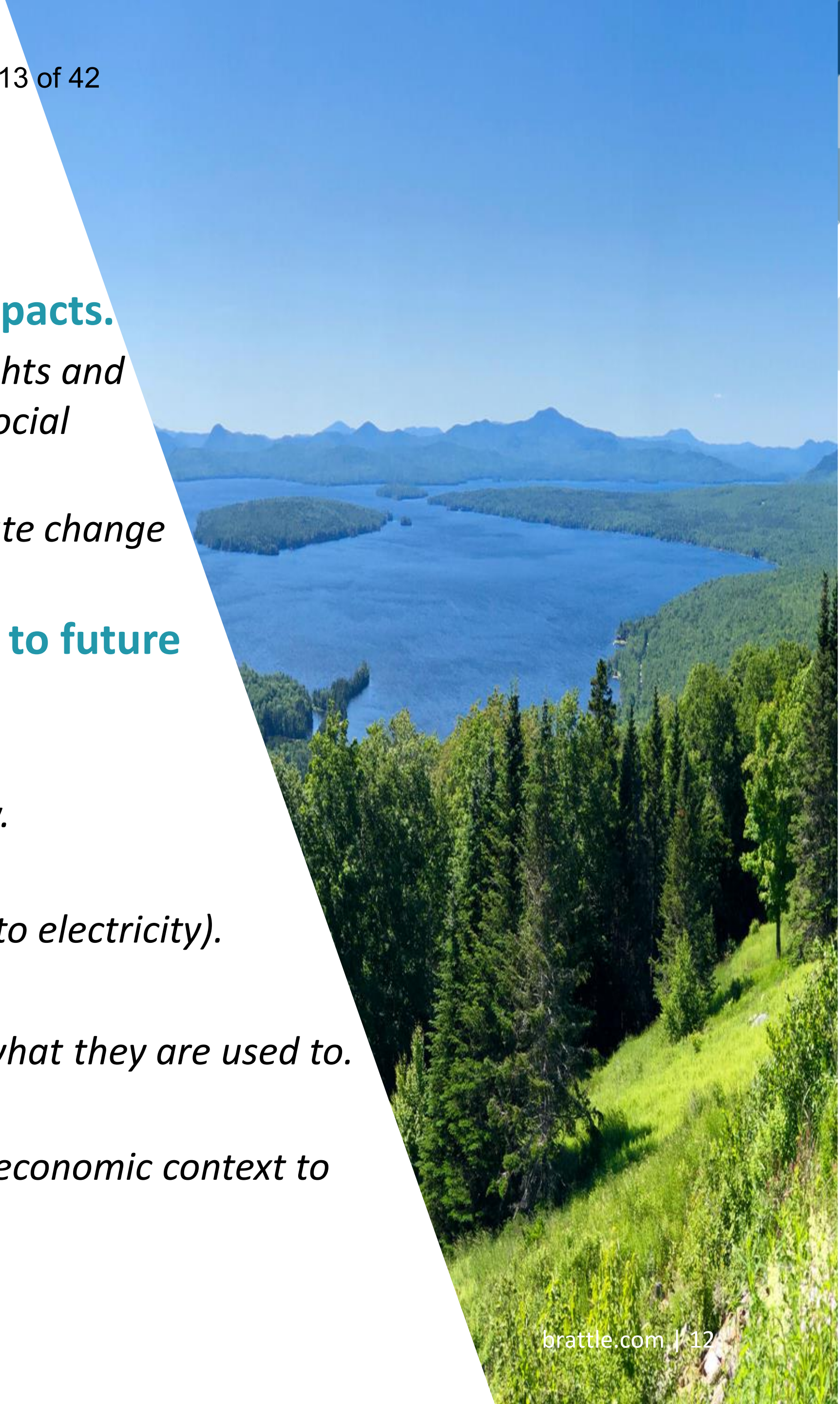
IWG Members on Climate Change: 1/2

- As part of its assignment, Brattle met with IWG members including: an in-person meeting with Ginoogaming First Nation on September 7; and a Zoom call with Minogi and Three Fires on September 26.
- **We heard how climate change is impacting First Nation communities' daily lives.**
    - *Extreme weather in both summer and winter -- longer hotter heat waves with more intense storms in the summer, and less snow but larger storms in the winter.*
        - *Heat waves typically use more energy as people try to keep their houses cool and food safe. High temperatures and wildfires make it difficult, and sometimes dangerous, to be outside on the land.*
        - *Longer shoulder seasons means shorter (if any) freeze on the lake and less ice fishing.*
    - *Local communities are having to relearn the habits of animals who are being impacted by changes in temperature and habitat.*
        - *It is distressing to see the loss of traditional animals, such as song birds, muskrats, porcupines, and moose - - or their well-being (some animals are getting sick far more often than in the past). At the same time, seeing invasive new animals appear such as wild hogs*
        - *The hotter summers raise lake water temperature and some fish species have to go farther from shore to find the colder water. Impacts on fish themselves are unknown.*
        - *For Treaty 9 coastal communities, the reduction in sea ice (4ft to 1ft) is changing traditional habitats with implications for local communities who are seeing increased numbers of bears seeking food.*
    - *There was a general concern whether traditional sources of food will be available for future generations.*



IWG Members on Climate Change: 2/2

- **The changes brought about by Climate change is having broader, societal impacts.**
  - *Climate change is impacting First Nation communities' ability to exercise their rights and stewardship over their lands, which is having an impact on health, cultural and social wellbeing of many people in the community.*
  - *Many communities already face many social and economic challenges, and climate change impacts are exacerbating them.*
- **We heard about Indigenous communities' goals and objectives with respect to future energy needs.**
  - *Important to be treated as equals with greater say in decision making.*
  - *Becoming energy self-sufficient, especially for times of crisis is desirable for many.*
  - *Rate stability and affordability is also very important.*
  - *Natural gas has been the lower cost fuel choice for heating purposes (compared to electricity).*
- **Opportunities, risks and challenges with respect to the Energy Transition.**
  - *Change management is sometimes hard for people to see things different from what they are used to.*
  - *IWG members are interested in helping address climate change.*
  - *Investments for the energy transition need to be made in the broader social and economic context to make sure all parties benefit from future prosperity.*



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Background

Energy Transition Plan of Enbridge Gas is in response to Federal and Provincial Climate Change goals

*In 2021, the Government of Canada committed to reducing its greenhouse gas emissions by 40% - 45% below 2005 levels by 2030, and to achieve **net zero emissions by 2050**.*

Enbridge Gas providing natural gas to ~3.9 million customers in Ontario has developed an Energy Transition plan to advance Ontario's 2030 GHG emissions reduction targets of 30% below 2005 by 2030

A significant reduction in natural gas consumption is a major risk to Enbridge's business. In response, Enbridge evaluated **two scenarios** to achieve net zero emissions by 2050.

1. Enbridge's preferred scenario is to develop new gas fuels called the "diversified scenario"

2. The alternative scenario is to replace today's gas usage with electricity called the "electrification scenario"

As part of a settlement agreement, Enbridge agreed with the Ontario Energy Board (OEB) to establish an ***Indigenous Working Group (IWG)*** to appropriately consider the unique rights and concerns of Indigenous customers and rights holders

- express concerns,
- guide the process on select topics
- identify opportunities.

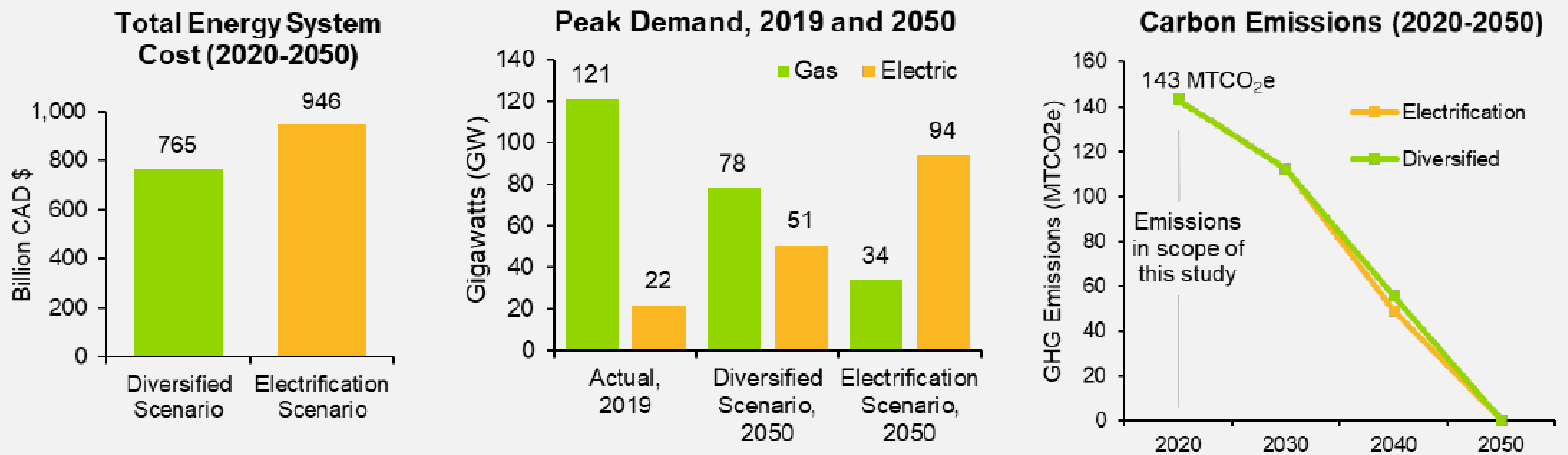
EGI estimates the cost to achieve net zero emissions by 2050 will be ~$800 billion or higher. Even though costs will be spread and collected over 40 years (like a mortgage), costs per customer could be quite large relative to current bills.

EGI Studies Review: **Two Scenarios**

Enbridge commissioned two studies outlining their energy transition scenario analysis (to achieve net zero by 2050).

1. A **Diversified Scenario** in which low and zero carbon gases [e.g., Renewable Natural Gas (RNG) and Hydrogen] and the gas delivery infrastructure are used in combination with end-use electrification to reduce GHG emissions in all sectors.
2. An **Electrification Scenario** that focuses on electrification of all sectors, with low and zero carbon gas use limited to cases

Figure ES-2. Comparison of Key Results for Diversified and Electrification Scenarios



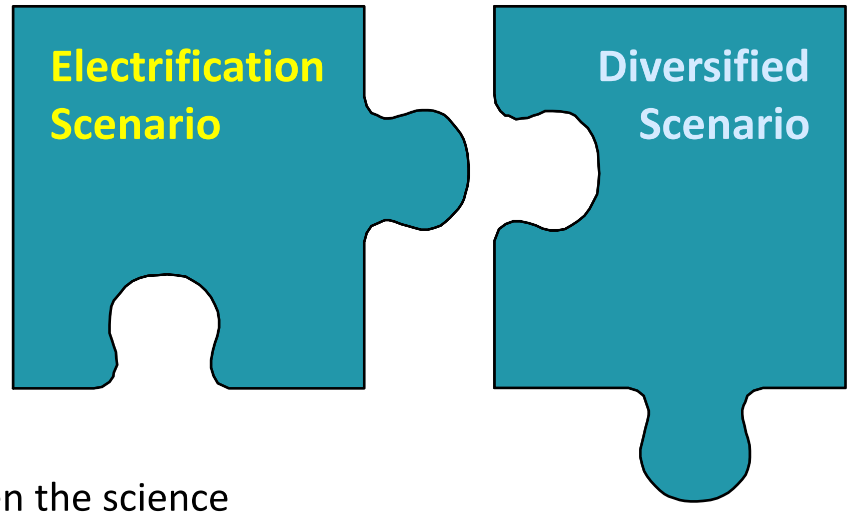
Ontario's GHG emissions today are ~16% from electricity, ~30% from gas, and ~45% from oil. Gas and oil usage are mainly for heating, industrial, and transportation.

Bottom Line: The two scenarios have significant implications for end use consumers with the electrification scenario requiring significant new additions of electricity infrastructure

EGI Reports Review: **IWG Member Perspectives**

The two studies provide framework for thinking of the transition --- but many questions remain.

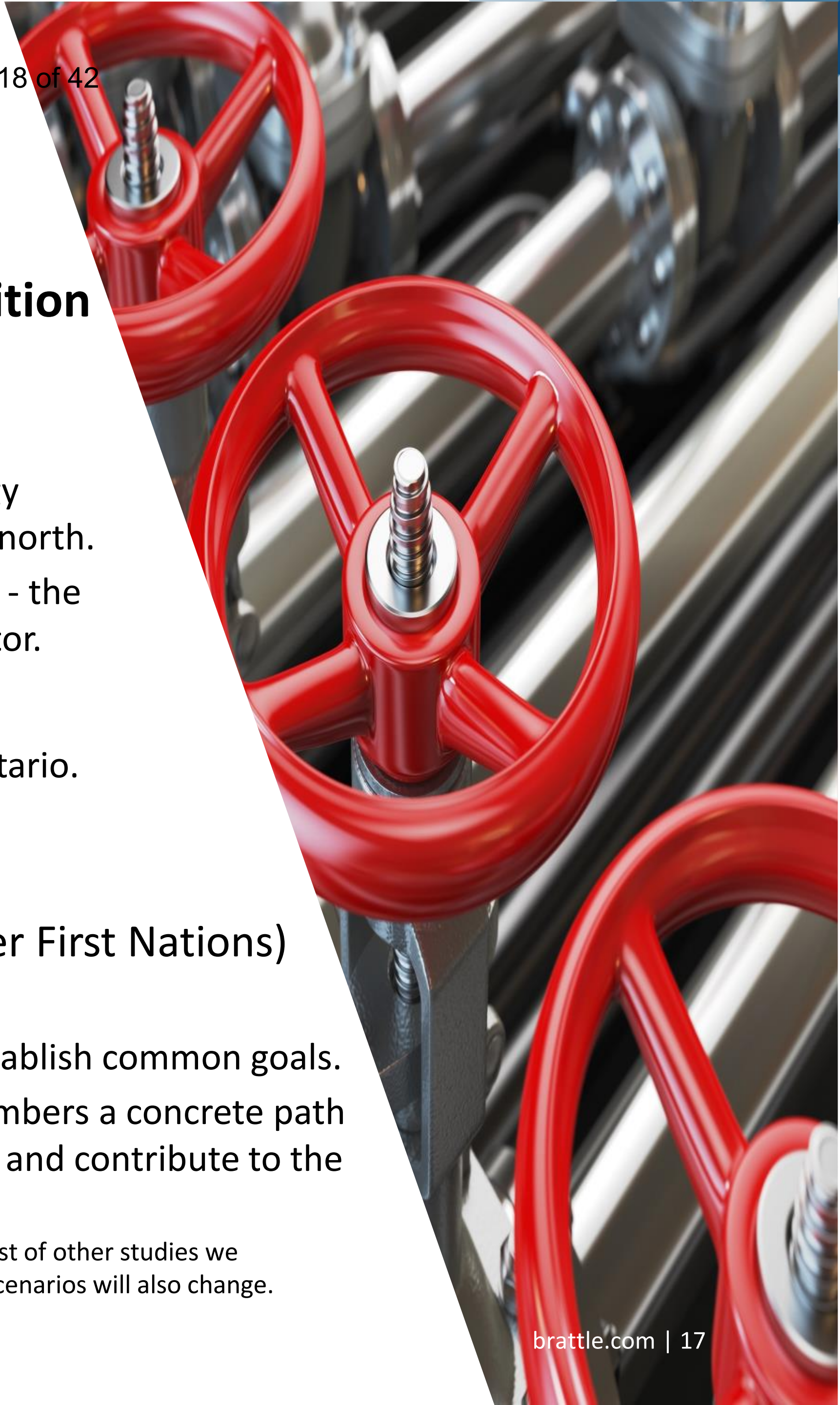
- EGI's transition plans do not explain how each option will impact land use and traditional activities such as environmental stewardship, which are a high priority for IWG members.
- IWG members believe that EGI's transition plans need to consider the "full lifecycle" of options presented. For example, will hydrogen production increase or decrease emissions when all the construction and input activities, such as the building of new pipes, compressors and electrolyzers, are included?
- EGI's transition plans contain options that include new or developing technologies, such as hydrogen and RNG fuels. How could EGI know the actual outcome of these technologies when the science is still being developed? Greater certainty is needed before making firm decisions.
- IWG members would like EGI to provide concrete examples of how their plans could impact IWG members' lives on a daily basis, even if they are illustrative.
  - For example, under the Diversified Scenario, what kind of new equipment would be built on First Nation's land and how would the First Nation's be compensated for that land usage? And under that scenario, what would the gas utility bill look like? Such examples would be helpful if they are provided for different timelines, such as of 2030, 2040, and 2050, or other representative timelines (that could be event-based, such as installation of a major equipment).



Brattle Assessment: **Overview**

The two studies provide useful framework for thinking of about the transition

- The two scenarios are not representations of what EGI will pursue and adopt uniformly but rather two illustrations of potential decarbonization paths.
  - The actual path will vary by location and customer needs. For example, heat pump technology today may be more suitable for southern Ontario and continued gas usage a necessity in the north.
  - The range and uncertainty of assumptions outweigh the granularity of the results presented* - the actual path will depend on technological advancements and interaction with the electric sector.
- Either pathway carries risks for gas users.
  - The reports don't address specifically how the two scenarios would affect First Nations in Ontario.
  - Both scenarios imply electricity becomes the preferred home heating fuel.
  - Electrification will affect all gas customers as less use will lead to higher rates.
- The transition provides opportunities for EGI, OEB, and IWG members (and other First Nations) to work together in achieving the decarbonization policy goal.
  - However, this requires concerted efforts from all parties (EGI, OEB, and IWG members) to establish common goals.
  - This is challenging since, given future uncertainties, EGI have not been able to show IWG members a concrete path forward which makes it extremely difficult for IWG members to see how they can participate and contribute to the process.



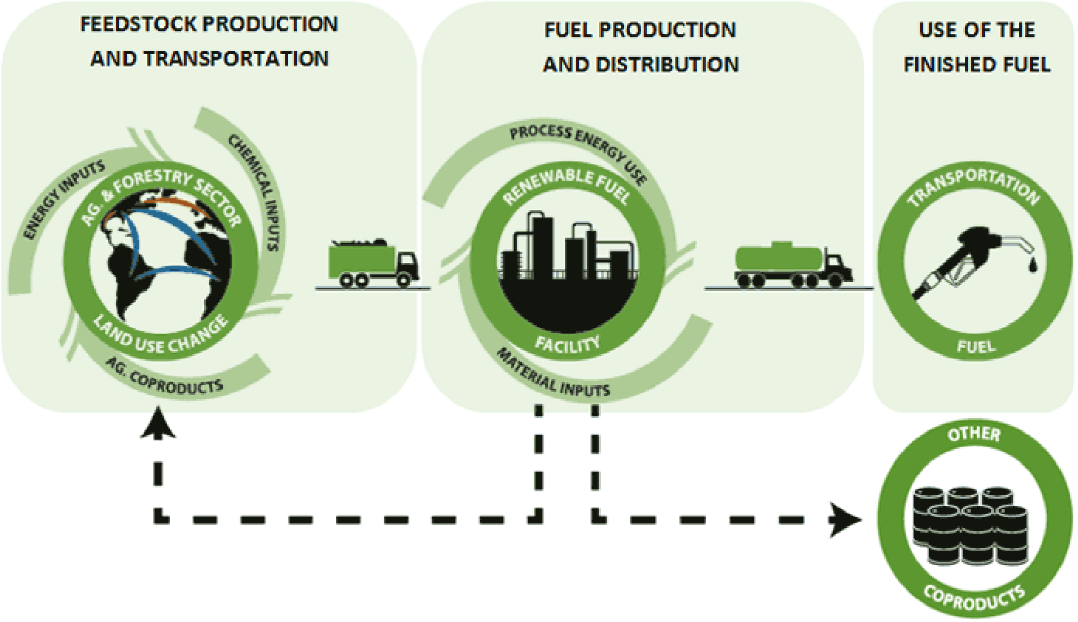
* For example, the EGI report's assumption on hydrogen costs are amongst the lowest of other studies we reviewed. Should the cost of hydrogen go up, the cost difference between the two scenarios will also change.

Filed: 2026-02-12, EB-2025-0155, Exhibit I.CCC-6, Attachment 1, Page 19 of 42

Brattle Assessment: **Need for Lifecycle Analysis**

Future studies will need to provide a complete environmental impact assessment across the full energy supply chain.

- The U.S. Environmental Protection Agency provides a useful framework to assess the full lifecycle environmental and GHG impact.
- The analysis includes indirect emissions at each stage of its production and use including the production of input fuels, transportation of fuels to a generation facility as well as any other emissions and environmental impacts resulting from its storage and use as applicable.
- Given the range of uncertainty, we would recommend **scenario modeling** to understand the risks (and mitigation options) at each stage and under different conditions.



Source: EPA's lifecycle analysis for the Renewable Fuel Standard

- Not every impact will be quantifiable. However, capturing potential indirect environmental impacts on land use, animal habitats will enable an informed discussion on the potential risks and opportunities posed by different energy plans.

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Brattle Assessment: **Need for Scenario Planning**

- Scenario-based planning* is a process first developed in the 1940s and 1950s as a tool for integrating uncertainties into long-term strategic planning:
  - Allows planners to think, in advance, about the many ways the future may unfold and how to respond effectively and flexibly as uncertain future outcomes become reality.
  - Ranks among the top-ten management tools in the world today.
- Scenario-based planning is a multi-step process:
  1. Define scenarios of plausible futures by scanning the current reality, trends and forecasts, uncertainties, and important internal and external drivers.
  2. Develop a series of plans (initiatives, projects, policies, tactics) that work well across multiple scenarios (e.g., by developing solutions that are flexible and robust across all plausible futures).
  3. Implement preferred plan and define indicators to alert planners that a certain future is likely to occur, so they can take action (e.g., exercise options to address the new developments).

Why is this Important?

The studies that have been prepared by EGI to date carry considerable environmental and economic risks for First Nations.

These can only be properly explored and assessed through scenario planning.

For example, First Nations need to understand what is the likelihood and scale of **potential stranded costs** they could incur under different outcomes.

Once the likelihood of key risks has been thoroughly assessed and understood, potential mitigation strategies can be developed.

The scenario planning process is as important as the results as it can facilitate far greater **participation and engagement** in the assessment process.

*Additional information can be found here: Living in the Futures (hbr.org) https://hbr.org/2013/05/living-in-the-futures and Scenario Planning-A Review of the Literature (mit.edu) https://scienceimpact.mit.edu/sites/default/files/documents/Scenario%20PlanningA%20Review%20of%20the%20Literature.PDF

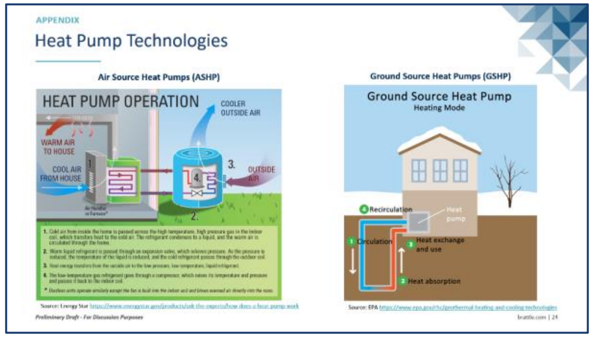
Brattle Assessment: **Transition Opportunities**

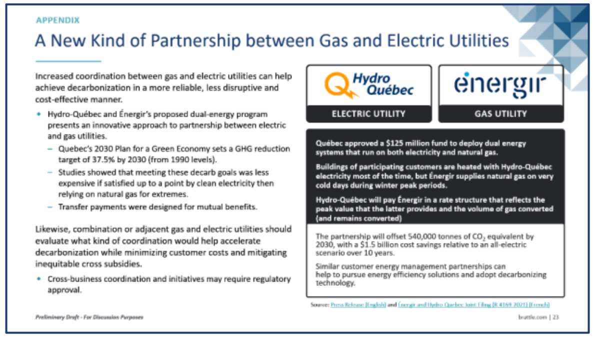
Brattle believe there are considerable opportunities to explore mutually beneficial economic opportunities that benefit all parties.

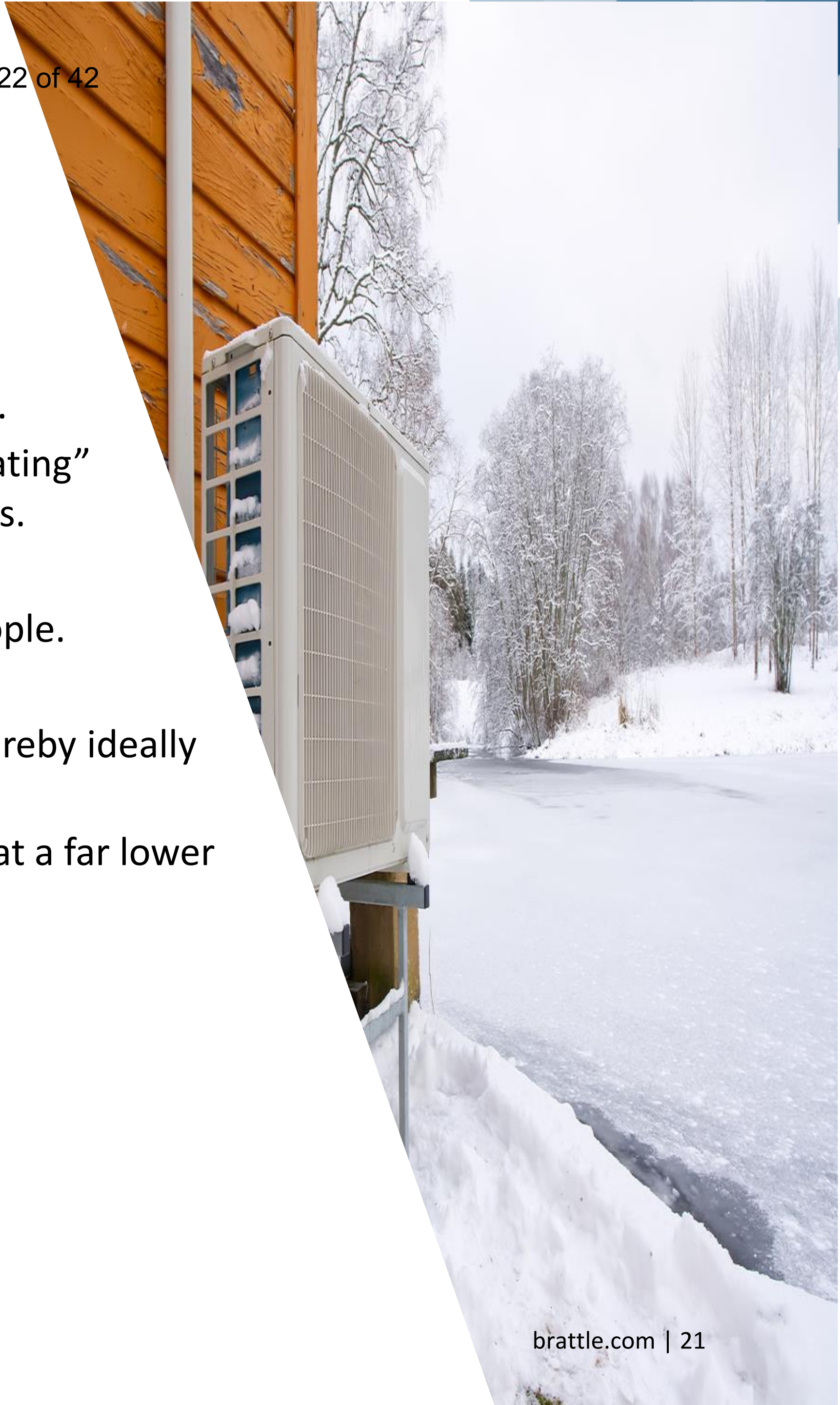
- Participate in Renewable Natural Gas (RNG) production.
  - Both scenarios include a lot of RNG production. IWG members could produce RNG either for their own use or to sell to others through the existing gas system. This could mitigate investment risks for EGI.
  - Partnership between EGI and Indigenous forestry corporations towards RNG through biomass is an example of such option.
- Partial ownership of gas distribution facilities.
  - There may be an interest in First Nation communities to take equity in the gas system serving their respective communities.
  - This could be combined with the RNG opportunity.
- Community-based electricity supply (e.g., wind/solar and energy storage systems).
  - The report identifies decentralized electricity generation (wind/solar with electricity storage) as an economic opportunity that would be beneficial to both the community and to the system as a whole. IWG members could develop such systems (or be part of the development).
  - GFN to work with Greenstone Municipality on upcoming landfill site towards renewable energy is an example of such option.

Brattle Assessment: **Transition Opportunities**

- Hybrid Heating.
  - A hybrid heating program that uses gas on colder days/locations and heat pumps otherwise could be beneficial to both EGI and EGI customers including IWG members.
  - While the EGI reports favor hydrogen, its sensitivity analysis also look at a "hybrid heating" program where customers would continue to have gas heat together with heat pumps.
  - Smaller steps that can be taken today include:
    - Improving heat pump accessibility by making the technology affordable for people.
    - Improving the technology and retrofitting to create equitable services.
  - These opportunities require coordination between EGI and the electric utility and thereby ideally should be led by OEB.
  - A similar program in Quebec estimates that it will have 80% of the emissions savings at a far lower cost than by using electric heating alone. (See appendix, slide 35)







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Brattle Assessment: **Transition Opportunities**

Both pathways also offer interesting opportunities to IWG members to voice concerns or impact policy development.

- First Nation communities expect to have greater decision-making powers, for example, relevant sections of the EGI transition plan could and should be reviewed and approved by the communities (or IWG).
- First Nation communities should have greater opportunity to be involved in higher policy-making and executive decision making.
- IWG members and other First Nation communities that will be directly impacted by EGIs plans should be compensated for past and future impacts.
  - Economic development opportunities.
  - Preferred skills training and employment opportunities.
  - Equity-sharing (and building) opportunities.
  - Offsetting to mitigate for disturbance of habitat on ancestral homelands.
  - Ongoing demonstrated and enhanced commitment to the environment.
- A share of future revenues for First Nation communities should be built into EGI's transition plans.

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Brattle Assessment: **Transition Opportunities**

EGI's planning process is an important opportunity for IWG members to develop visions of their own energy future.

- The vision can be as an energy user or as a potential owner of energy assets.
- Asset ownership could help EGI contain its capital needs (which according to the EGI studies will likely be in the 100s of billion dollars range).
  - Asset ownership would certainly give the community greater control over its energy future.
  - Asset ownership could help internalize costs within the community. It may also provide opportunities to develop skillsets (e.g., maintenance of assets) and lead to employments, which will also help internalize costs.
  - Asset ownership entails stranded asset risks. For example, if the community in the future decides to abandon the usage of gas, the assets the community purchased will likely lose their values, unless an alternative purpose can be found.
- The vision should reflect IWG members' respective values and developed considering associated trade-offs, such as the price/cost threshold for pursuing an objective (e.g., economic value of carbon reduction)

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IWG Members' Voices: **Engagement Process**

- EGI's plans have the potential to impact many First Nation communities across Ontario and thereby the establishment of IWG on itself was received as a positive movement.
- However, to date IWG members have been disappointed by the degree of EGI's engagement on its transition plans at the IWG meetings and raised concerns with:
  - **Engagement approach** – EGI needs to proactively engage all impacted communities and ensure its engagement is sufficiently comprehensive to address all the impacts its energy transition plans will have on local communities.
  - **Structure and resources** – IWG members have limited time and resources and look to EGI to provide greater leadership and make available more resources to allow IWG members to conduct their own assessments.
  - **Information sharing** - EGI should bring representatives to IWG meetings that are able to answer all important questions and concerns raised by IWG members.
  - **Scope** - the IWG is not enough to address the challenges posed by the energy transition, which include many aspects and entities beyond EGI (electricity for example), along with policy changes (address affordability for example).
- Overall, the IWG members feel as if the IWG consultation process does not have the priority and resources from EGI that is required be an effective forum to enable members to ensure their voices are heard and included in important decisions.

IWG Improvement Needs: **Engagement**

- To date EGI engagement through the IWG has not been as effective as other comparable consultations.
  - There has been no direct contact initiated by EGI towards First Nation communities - which makes IWG members question EGI's commitment to truly understand the impact of its plans on First Nation communities.
  - Similar processes taken by other industries have been more attentive (e.g., a First Nation community worked with the Greenstone mine for 15 years and met in-person frequently.).
  - The format and management of the EGI consultation process provided through the IWG is not as comprehensive as other large energy sector entities such as the Independent Electric System Operator (IESO) and the OEB.
  - EGI's transition plans have the potential to impact many Indigenous peoples across Ontario. A common approach is needed when EGI's pipelines impact so many communities. Yet, no such approach has been proposed, nor discussed to date.
- Engagement concerns are heightened since IWG members feel that they are only being consulted because they inserted themselves into the EGI process.
  - IWG members and other First Nation communities should not have to pursue legal route to have their voices heard on issues that have direct impacts on their people and traditional lands.
  - One IWG member noted that there is a difference between the actions of EGI in Ontario and the parent company in Calgary, Alberta. Enbridge Inc. has developed an Indigenous Reconciliation Action Plan but IWG members do not believe EGI's actions and policies in Ontario are aligned with or consistent with this Plan.
  - An IWG member expressed the view succinctly "Indigenous peoples should be consulted at the creation of the plan, not at the end" - yet, there has been no presentation or discussion by EGI on its Energy Transition Plans with IWG members.

IWG Improvement: **Structure and Resourcing**

- Some IWG members expressed frustration with procedural aspects of the IWG meetings that are limiting its effectiveness.
  - The IWG would benefit from clear goals and objectives that provide EGI and IWG members with a common understanding of what the IWG is aiming to achieve by 2028 – these could be established in a Terms of Reference that would also set out roles, responsibilities and expectations
  - Communication could be improved, especially for those who cannot attend IWG meetings since there is no public webpage to record IWG meeting minutes/presentation materials
- IWG members understand EGI to be a large company with significant resources, knowledge and capacity, and needs to do more to share these resources with local communities they serve and impact.
  - IWG members and other First Nation communities do not have access to the same resources and education is critical in order to create a level playing field and allow Indigenous peoples to accurately understand what is being proposed and provide meaningful input.
  - EGI has a responsibility to help educate their consumers on the potential impacts of their transition plans in a way that is understandable to the local communities.
  - Resources should be made available to enable the IWG members and First Nation communities to undertake their own analysis (e.g., economic or scientific modeling) so that they can make informed decisions on options and solutions that will impact the daily lives of their communities.

IWG Improvement: **Information Sharing**

- To date IWG members and EGI appear to have different working objectives for the IWG
  - IWG members wish to discuss the potential impacts, options and risks associated with EGI's energy transition plans that include economic and social impacts.
  - EGI is primarily focused on how to create and build support for new business opportunities to sustain its business model.
  - There is considerable potential overlap with both goals, but EGI needs to ensure it is giving due consideration to the very clear concerns expressed by the IWG.
- This disconnect has resulted in dissatisfaction from all parties and led to the lack of sharing important information for IWG members.
- Having the right EGI representatives at the IWG meetings is important to ensure EGI is effectively listening to the concerns and questions of IWG members.
  - EGI representatives at the IWG meetings, to date, have not been able to answer important questions such as impacts on local communities, scientific information on the viability of hydrogen or other solutions.
  - The absence of EGI senior leadership limits any discussion on bigger picture issues such as electricity and policy overlaps which is needed when discussing the structural changes being proposed by EGI.
  - The absence of the right EGI representatives makes IWG members feel as if EGI is "ticking a box" rather than being serious about listening to local communities about the potential impacts.

Scope of IWG and Energy Transition: 1/2

- IWG members believe that the scope of the IWG, which focuses on EGI's transition plan, may not be adequate.
  - IWG member communities noted that important decisions that impact the daily lives of First Nation communities are being made by the Ontario government and these decisions are imposed on First Nation communities despite their Treaty rights.
  - For example, IWG communities would like to plant more trees to sequester carbon. However, such decisions are made by the Ontario government and IWG members feel strongly that First Nation communities should have greater say on these decisions.
- The transition scenarios EGI has outlined requires electrification (e.g., heat pumps) to reduce gas consumption. Identifying the optimal path requires collaboration with the electric utility, which the IWG does not expand to.
  - Greater electrification would mean most First Nation communities would need to be connected to Hydro One network. Like EGI, Hydro One has a monopoly on supplying rural regions and does not offer the same electrification options as other urbanized utilities such as Alectra or Elexicon.
- Structural issues need to be address to ensure coordinated planning.
  - Ontario does not have an integrated planning process for "energy" (electricity and natural gas among other potential energy sources).
  - The OEB regulates electricity and natural gas, and the IESO is the primary system planner almost exclusively focused on electricity without a natural gas counter-part. In that sense, expanding the IWG scope may be difficult, until the energy planning framework is coordinated.

Scope of IWG and Energy Transition: 2/2

- IWG members highlighted how the current energy policy framework does not adequately reflect or include the rights of First Nation communities who have formal agreements with federal and provincial governments.
  - If a goal of the energy transition is to create shared prosperity, then more effort is needed to respect First Nation Treaty rights and appropriately compensate for any historical or future impacts.
- IWG members emphasized that “equality” is a high priority and noted several examples they are not being treated as equals with respect to energy consumption.
  - Electric solutions often require significant upfront capital to provide the degree of home insulation needed to keep costs down. Caldwell First Nation was cited as an example where a new community housing uses an all-electric solution. However, the community had challenges securing capital to make the necessary investments.
  - At the current time Ontario does not have an economic reconciliation policy. IWG members highlighted that there has been some progress with individual companies such as Metrolinx and Ontario Power Generation, where community support is essential for new projects. However, in the absence of clear provincial policy to ensure all companies engage and include First Nation communities, companies are not applying a common standard consistent with reconciliation.

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Discussion, Questions, and Next Steps

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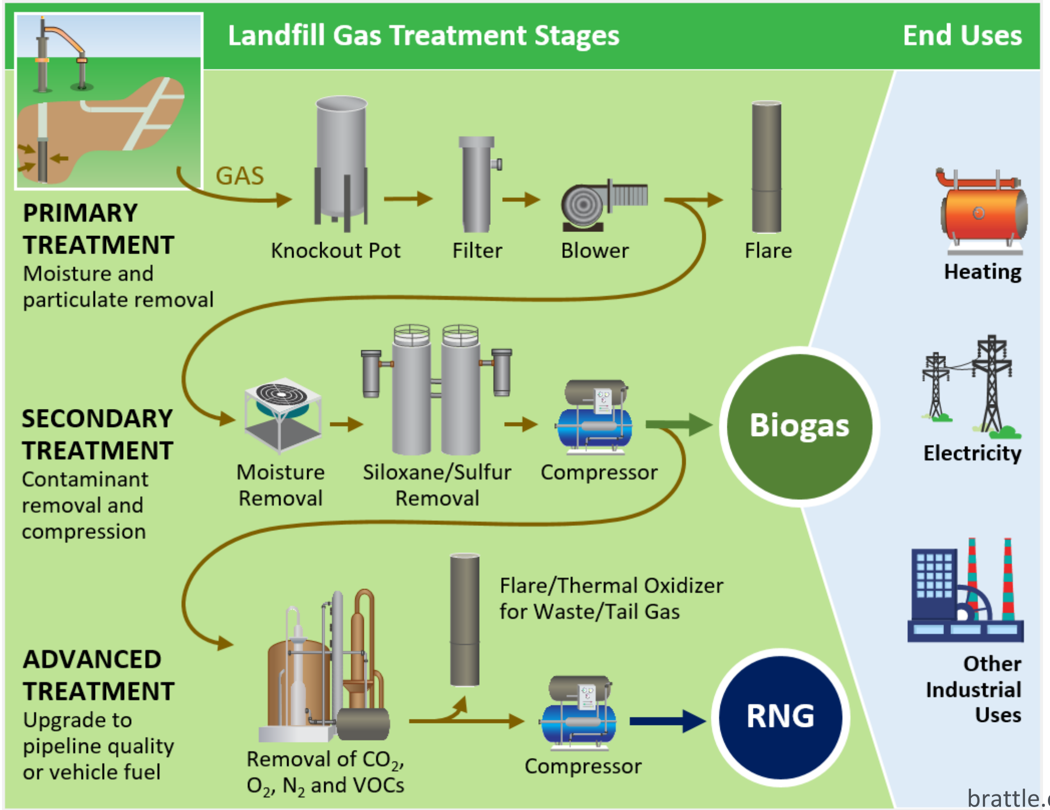
EGI's Energy Transition Study Results

Table 1: Key Differences for 2050

Scenario	Cost [$ billion]	Electricity Consumption [TWh]	Methane Usage (including RNG) [PJ]	Hydrogen Usage [PJ]	Total Gas Usage [PJ]	Electricity Peak Demand and *Generation Capacity [GW]*	Wind Generators [GW]	Hydrogen-fueled Generators [GW]/[GWh]
Diversified	$765 - Gas: $177 - Elect:$354 - Emissions: $120 - End Users: $114	277 TWh (2x of today)	310 PJ (1/3x of today)	839 PJ	1149 PJ - Buildings: 391 PJ - Industry: 486 PJ - Transportation: 276 PJ	51 GW Peak (2.5x of today) *116 GW Capacity* *(3x of today)*	68 GW	48 GW (193 GWh)
Electrification	$946 - Gas: $119 - Elect:$466 - Emissions: $191 - End Users: $170	435 TWh (3x of today)	182 PJ (1/5x of today)	262 PJ	444 PJ - Buildings: 80 PJ - Industry: 186 PJ - Transportation: 170 PJ	94 GW Peak (4x of today) *166 GW Capacity* *(4x of today)*	84 GW	15 GW (53 GWh)
Today (2020)		135 TWh	922 PJ	0 PJ	922 PJ - Buildings: 594 PJ - Industry: 378 PJ - Transportation: 0 PJ	22 GW Peak *40 GW Capacity*	5.5 GW	0 GW (0 GWh)

Renewable Natural Gas (RNG)

- RNG is a broad term that includes gaseous biofuels derived from the *breakdown of biological matter* through anaerobic digestion.
- *Biogas* is produced from the breakdown of various waste streams and is a combination of methane, CO2, and other gases.
  - 90% of current U.S. biogas is produced from solid waste in landfills or organic matter in water treatment plants.
- Biogas is "upgraded" to *pipeline quality RNG* and is injected into natural gas distribution systems.
  - RNG is molecularly equivalent to methane (natural gas).
- RNG prices are based on long-term bi-lateral contracts between developers and utilities, currently 3x to 5x of natural gas prices.
  - There is not a liquidly traded RNG market (similar to natural gas).



A New Kind of Partnership between Gas and Electric Utilities

Increased coordination between gas and electric utilities can help achieve decarbonization in a more reliable, less disruptive and cost-effective manner.

- Hydro-Québec and Énergir's proposed dual-energy program presents an innovative approach to partnership between electric and gas utilities.
  - Quebec's 2030 Plan for a Green Economy sets a GHG reduction target of 37.5% by 2030 (from 1990 levels).
  - Studies showed that meeting these decarb goals was less expensive if satisfied up to a point by clean electricity then relying on natural gas for extremes.
  - Transfer payments were designed for mutual benefits.

Likewise, combination or adjacent gas and electric utilities should evaluate what kind of coordination would help accelerate decarbonization while minimizing customer costs and mitigating inequitable cross subsidies.

- Cross-business coordination and initiatives may require regulatory approval.

Hydro Québec

ELECTRIC UTILITY

énergir

GAS UTILITY

Québec approved a $125 million fund to deploy dual energy systems that run on both electricity and natural gas.

Buildings of participating customers are heated with Hydro-Québec electricity most of the time, but Énergir supplies natural gas on very cold days during winter peak periods.

Hydro-Québec will pay Énergir in a rate structure that reflects the peak value that the latter provides and the volume of gas converted (and remains converted)

The partnership will offset 540,000 tonnes of CO_2 equivalent by 2030, with a $1.5 billion cost savings relative to an all-electric scenario over 10 years.

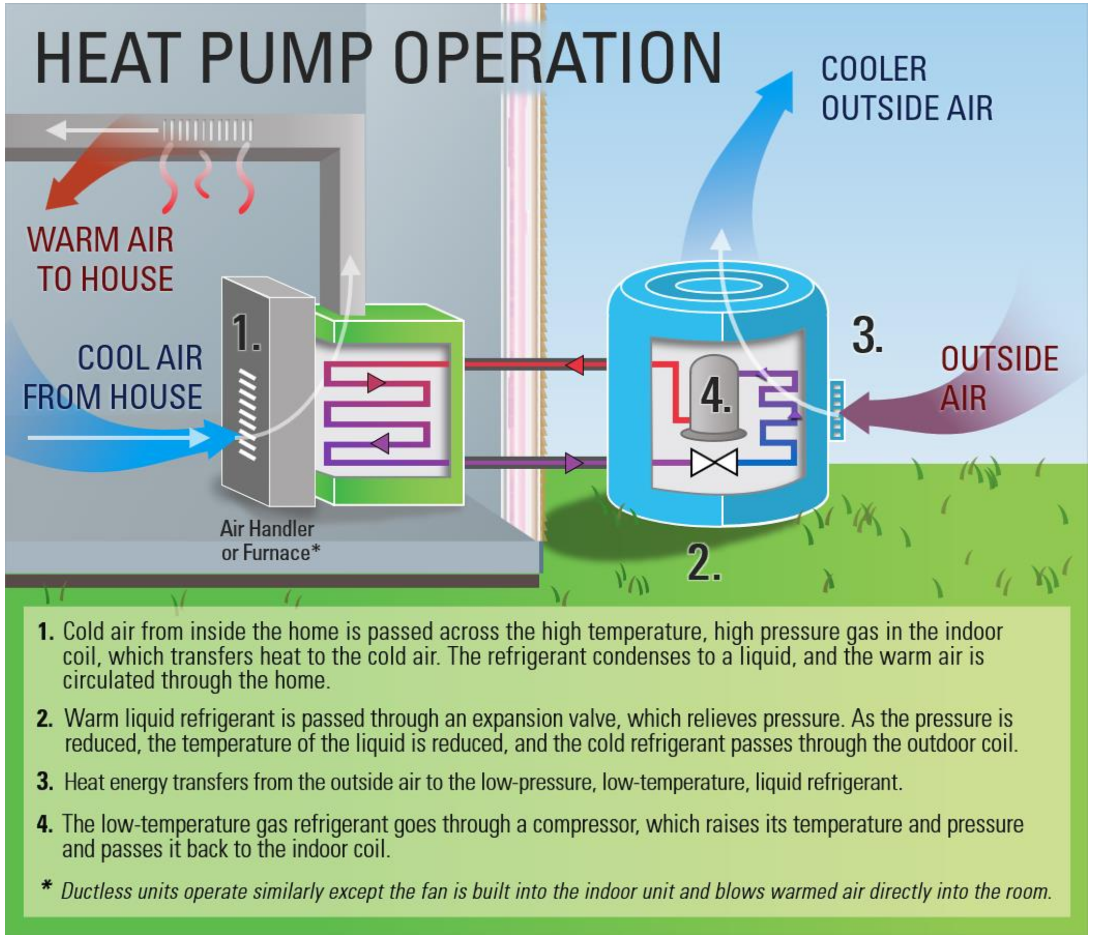
Similar customer energy management partnerships can help to pursue energy efficiency solutions and adopt decarbonizing technology.

Source: Press Release (English) and Énergir and Hydro-Quebec Joint Filing (R-4169-2021) (French)

Filed: 2026-02-12, EB-2025-0155, Exhibit I.CCC-6, Attachment 1, Page 38 of 42

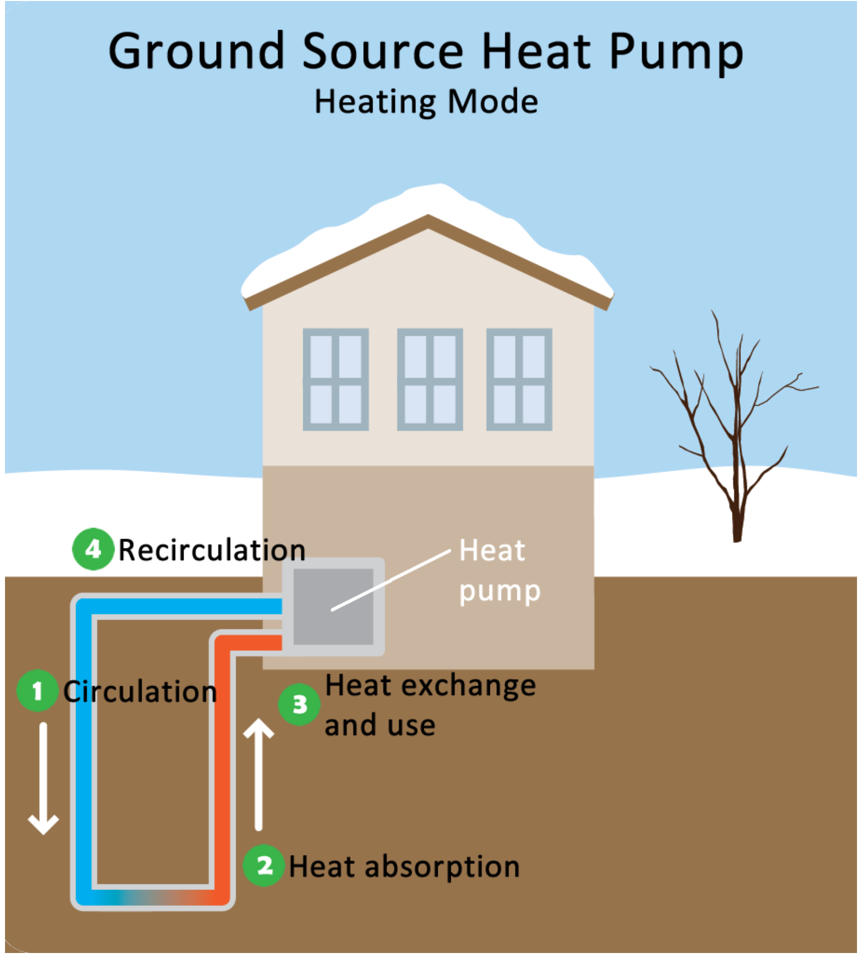
Heat Pump Technologies

Air Source Heat Pumps (ASHP)



Source: Energy Star https://www.energystar.gov/products/ask-the-experts/how-does-a-heat-pump-work

Ground Source Heat Pumps (GSHP)



Source: EPA https://www.epa.gov/rhc/geothermal-heating-and-cooling-technologies

Glossary and Units

Glossary

- EGI Enbridge Gas, Inc.
- GHG Greenhouse Gas
- IESO Independent Electric System Operator
- IWG Indigenous Working Group
- OEB Ontario Energy Board
- RNG Renewable Natural Gas

Units

- PJ Petajoule (1,000,000,000,000,000 joules)

In electricity terms, 1 PJ is about 278 GWh, or the amount of electricity used by 24,000 houses for a full year.
2,000 kcal (average amount of energy needed for an adult) is about 8,700 joules.

- GW Giga-Watt (1,000,000 kW)
- GWh Giga-Watt Hours (1,000,000 kWh)
- TW Tera-Watt (1,000,000,000 kW)
- TWh Tera-Watt Hours (1,000,000,000 kWh)

In electricity terms, 1 GWh is about the amount of electricity used by 90 houses for a full year.

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ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 18, pp. 2-3

Question(s):

a) Please provide the relevant excerpts from the EB-2022-0200 proceeding that highlight the locate-related amounts built into base rates, how those amounts were derived, and any narrative regarding the inclusion, or lack thereof, of Bill 93-related impacts on the 2024 locate-related forecast.

b) Please provide the same information as is provided in Table 1 for the 2024 forecast locate-related costs (as estimated in the EB-2022-0200 proceeding).

Response:

a) The 2024 forecast budget for locates included external costs of $51.1 million. This amount took into account inflation, cost pressures from various sources, and early estimates from 2022 of the impacts related to Bill 93[1], Enbridge Gas was clear at all times that the 2024 budget was conservative and likely did not include all costs that would result from Bill 93. For that reason, Enbridge Gas sought approval for a variance account to record and recover additional costs associated with Bill 93.

In the request for generic variance account proceeding[2] seeking approval of the GOCA variance account for distribution utilities, Enbridge Gas filed a compendium setting out all the evidence in the 2024 Rebasing Phase 1 proceeding[3] addressing locates costs. A copy of the compendium and associated cover letter are included as Attachment 1.

It bears note, that Enbridge Gas's 2024 forecast budget for external costs related to locates of $51.1 million was part of the Company's overall O&M budget of $821 million (net of overhead capitalization). In the OEB-approved Settlement Proposal, parties agreed to reduce the O&M budget by $50 million (or 6.1%)[4].

[1] EB-2022-0200, Exhibit I.4.4-STAFF-122.
[2] EB-2023-0143.
[3] EB-2022-0200.
[4] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.30.

Notwithstanding that reduction, Enbridge Gas has used the unadjusted forecast of $51.1 million in locate costs as the comparator for the GOCA variance account.

b) Table 1 at Exhibit C, Tab 2, Schedule 18 contains actual values for locate numbers and costs for 2019 to 2024.

The evidence filed in the 2024 Rebasing Phase 1 proceeding[5] (which was prepared in 2022) did not specify the number of locates that were assumed or forecast to arrive at the forecast $51.1 million for external locate costs. Enbridge Gas has reviewed its records and the best information that can be found indicates that at the time that the 2024 Rebasing Phase 1[6] evidence was prepared, the Company was expecting an increased number of locates for 2024, in the range of 1.17 million. This increased locates volume (as compared to the most recent actuals at that time for 2020 and 2021) may have reflected an expectation of post-COVID recovery. Using a forecast of 1.17 million locates for 2024, along with a $51.1 million budget, implies a per-locate cost of $44. This is substantially higher than the most recent full-year actuals known when the rebasing evidence was prepared ($32 per locate in 2021). It is, however, substantially lower than the actual costs experienced.

Table 1 sets out the forecast locate volumes and costs for 2024 (using the best information that the Company can locate), along with the actual locate volumes and costs for the 2019 to 2024 period (reproducing Table 1 from the evidence).

Table 1
2019-2024 External Locate Costs

Line No.	Particulars	2019	2020	2021	2022	2023	2024	2024 Forecast
1	Total Locates (millions)	1.1	1.01	1.07	1.02	0.98	0.99	1.17
2	Total External Costs for Locate Delivery ($ millions)	$38.4	$33.5	$34.5	$39.9	$65.8	$66.0	$51.1
3	Average Cost per Locate ($ dollars)	$35	$33	$32	$39	$67	$67	$44
4	Average Unit Cost Variance vs. 2021	-	-	-	21%	109%	108%	37%

[5] EB-2022-0200.
[6] Ibid.

ENBRIDGE

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Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

July 25, 2023

VIA RESS AND EMAIL

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, On M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2023-0143
Request for generic variance account - supporting evidence

On June 14, 2024, the OEB notified a group of large Ontario natural gas and electricity local distribution companies (the Large Utilities) and the Electricity Distributors Association (collectively the Parties) in a Letter of Direction to direct Parties to produce evidence related to the establishment of a generic, sector-wide variance account to track the incremental costs of locates in 2023 and future years arising from the implementation of recent Provincial legislation: Bill 93 (getting Ontario Connected Act, 2022).

In favour of the OEB determining a generic variance account for the Parties in EB-2023-0143, on May 24, 2023, Enbridge Gas filed a letter withdrawing its request for a locate delivery charge and a locate delivery services variance account from the 2024 Rebasing Application. Enbridge Gas did reserve the right to separately seek approval of a locate delivery charge as part of Phase 2 in the 2024 Rebasing proceeding, if the OEB does not issue a generic variance account for the purposes of locates.

Attached to this letter is a compendium of supporting evidence regarding the request for a generic variance account that was originally filed in Enbridge Gas's 2024 Rebasing proceeding.

Should you have any questions, please contact the undersigned at 416-495-5499 or via email at EGIRegulatoryProceedings@enbridge.com.

Sincerely,

Lesley M Austin

Digitally signed by Lesley M Austin
Date: 2023.07.25 16:37:50 -04'00'

Lesley Austin
Regulatory Applications, Regulatory Affairs
Enbridge Gas Inc.

cc: Andrew Frank, Sr. Advisor, Electricity Distribution: Major Rate Applications and Consolidations, OEB
Christine Long, Vice President, Regulatory Affairs & Privacy Office, Alectra Utilities Corporation
Stephen Vetsis, Vice President, Regulatory Affairs and Stakeholder Relations, Elexicon Energy Inc.
Frank D'Andrea, Vice President, Regulatory Affairs, Hydro One Networks Inc.
April Barrie, Director, Regulatory Affairs, Hydro Ottawa Limited
Scott Mudie, EVP, Chief Energy Transformation Officer, Oakville Hydro Electricity Distribution Inc.
Andrew Sasso, Director, Energy Policy & Government Relations, Toronto Hydro-Electric System Limited
Brittany Ashby, Senior Regulatory Affairs Advisor, Electricity Distributors Association
Mark Kitchen, Director Regulatory Affairs, Enbridge Gas Inc.

Attachment

Enbridge Gas Compendium

EB-2023-0143 - Request for Generic Variance Account Compendium of Supporting Evidence

Tab 1	EB-2022-0200 – 2024 Rebasing Application - Evidence – Updated: 2023-03-08, Exhibit 9, Tab 1, Schedule 3, pp. 8 – 11. (Miscellaneous Service Charges)
Tab 2	EB-2022-0200 – 2024 Rebasing Application -Evidence – Filed: 2022-11-30, Exhibit 8, Tab 3, Schedule 1, pp. 13 – 21.
Tab 3	EB-2022-0200 – 2024 Rebasing Application – Interrogatory Responses • Exhibit I.4.4-STAFF-122 • Exhibit I.9.1-CCC-102 • Exhibit I.9.1-OGVG-12 • Exhibit I.9.1-SEC-228
Tab 4	EB-2022-0200 – 2024 Rebasing Application -Technical Conference - Day 3 Transcript pp. 206 – 212, March 24, 2023. (Panel 11 - SQRs, DVAs (non-gas), service charges)
Tab 5	EB-2022-0200 – 2024 Rebasing Application - Technical Conference – Day 7 Transcript pp. 95 – 98, March 30, 2023. (Panel 6 - O&M costs, Corporate Cost Allocation)
Tab 6	EB-2022-0200 – 2024 Rebasing Application -Technical Conference Hearing Exhibit KT3.4.
Tab 7	EB-2022-0200 – 2024 Rebasing Application -Technical Conference Undertaking – JT3.38.
Tab 8	EB-2022-0200 – 2024 Rebasing Application - Settlement Proposal Filed: 2023-06-28, Exhibit O1, Tab 1, Schedule 1, pp. 1, 4, 51-52, 55-57.
Tab 9	EB-2022-0200 – 2024 Rebasing Application - Enbridge Gas Letter - Withdrawal of Requests for Locate Delivery Charge & Locate Delivery Services VA (May 24, 2023).

TAB 1

ESTABLISHMENT OF NEW DEFERRAL AND VARIANCE ACCOUNTS

JASON VINAGRE, MANAGER REGULATORY ACCOUNTING
RYAN SMALL, TECHNICAL MANAGER REGULATORY ACCOUNTING

1. The purpose of this evidence is to request OEB approval to establish new deferral and variance accounts (D&VAs). The request for each account is supported by how the Company has met the OEB eligibility requirements for new D&VA requests.

2. Enbridge Gas proposes to establish the following new variance accounts, effective January 1, 2024.
    1. Energy Transition Technology Fund Variance Account (Account No. 179-321)
    2. Rate Harmonization Variance Account (Account No. 179-322)
    3. Dawn Parkway Surplus Capacity Deferral Account (Account No. 179-323)
    4. Locate Delivery Services Variance Account (Account No. 179-324)
    5. Open Bill Extension Deferral Account (Account No. 179-325)
    6. Enhanced Distribution Integrity Management Program Deferral Account (Account No. 179-326)
    7. Post-Retirement True-Up Variance Account (Account No. 179-328) /u

3. The Filing Requirements for Natural Gas Rate Applications (Filing Requirements) require a new D&VA request be accompanied by evidence on how the following eligibility criteria will be met[1]:
    a) Causation – the forecasted expense must be clearly outside the base upon which rates were derived;

[1] Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.38.

b) Materiality – the forecasted amounts must exceed the OEB-defined materiality threshold[2] and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements; and,

c) Prudence – the nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

4. The proposed Accounting Orders for the new D&VAs are provided at Exhibit 9, Tab 1, Schedule 1, Attachment 3.

<u>1. Energy Transition Technology Fund Variance Account (Account No. 179-321)</u>

5. Enbridge Gas proposes to establish the Energy Transition Technology Fund (ETTF) Variance Account as a tracking account over the IR term. In order to achieve provincial and federal greenhouse gas (GHG) reduction targets, Enbridge Gas is exploring and pursuing multiple energy transition-related initiatives that will reduce GHG emissions from Enbridge Gas's own operations as well as from buildings, industry, and transportation. A description of these initiatives is provided at Exhibit 1, Tab 10, Schedule 1. As part of its proposed initiatives, Enbridge Gas is requesting approval of the ETTF, which is intended to support research, development, and commercialization of low carbon technologies. A description of the proposed ETTF is provided at Exhibit 1, Tab 10, Schedule 7.

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[2] The materiality threshold is set at $1 million for a utility with a revenue requirement of more than $200 million, as defined in the Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.38.

6. Enbridge Gas is proposing to collect $5 million forecasted annually over the IR term, which will accumulate in the proposed ETTF Variance Account. As ETTF expenses are incurred, the accumulated balance in the variance account will be drawn down. Enbridge Gas proposes to review the balance in the variance account at the next rebasing application.

7. Enbridge Gas proposes to collect the ETTF through a rate rider, as provided at Exhibit 8, Tab 1, Schedule 1. Collecting the ETTF through a rate rider, as opposed to base rates, provides transparency, as the actual amount collected for the ETTF will be earmarked for the ETTF, underscoring the importance of having a dedicated, continuous, reliable funding stream for technology research and innovation, and giving ratepayers confidence that this is an on-going priority for Enbridge Gas. It also removes the amounts collected for the ETTF from escalation[3] during the IR term. There are no associated costs in the budget underpinning the forecast revenue requirement. As a result, the $5 million forecasted to be collected for the ETTF is incremental to the proposed 2024 revenue deficiency.

8. Enbridge Gas has assessed the causation, materiality, and prudence of the ETTF Variance Account:
   a) Causation – All costs that Enbridge Gas intends to record in the proposed ETTF Variance Account are outside of the base upon which rates are derived. The Company is proposing a rate rider to collect the required funding for GHG reduction initiatives.
   b) Materiality – Enbridge Gas's forecasted spend exceeds the $1 million materiality threshold for the establishment of new accounts. The Company is

[3] Enbridge Gas is proposing annual rate adjustments using a Price Cap Index during the 2025 to 2028 IR term.

proposing $5 million annually in ETTF funding, for a total of $25 million forecasted to be collected over the IR term, which will be tracked in the variance account. These funds are intended to support customers and the Company through a period of significant Energy Transition over time.

c) Prudence – Enbridge Gas's proposed fund for energy transition technology development is critical to address the challenge of climate change and energy transition policies in Ontario and Canada, to satisfy customers' feedback on energy transition, and to deliver the Company's overall energy transition plan. Please see Exhibit 1, Tab 10, Schedule 7 for greater detail on the purpose and scope of the proposed ETTF.

<u>2. Rate Harmonization Variance Account (Account No. 179-322)</u>

9. Enbridge Gas proposes to establish the Rate Harmonization Variance Account (RHVA) to record material differences to forecast revenues that are attributable to customers switching rate classes as a result of the implementation of the rate harmonization plan. Implementation of the rate harmonization plan is currently planned for 2025 for general service customers and for 2026 for contract service customers. Please see Exhibit 7, Tab 1 for the harmonized cost allocation and Exhibit 8, Tab 2 for the rate harmonization plan.

10. The cost allocation and rate design process to support the rate harmonization plan is underpinned by a harmonized customer forecast. Enbridge Gas prepared the harmonized customer forecast by placing customers into harmonized rate classes based on the customer's current parameters and service option. For example, a firm bundled contract rate customer is placed in the corresponding firm bundled contract rate class for purposes of deriving the harmonized customer forecast. The mapping of current rate classes to proposed rate classes is provided at Exhibit 8, Tab 2, Schedule 1, Attachment 1. This approach ensured that there was no

judgment by the Company on what service option a customer may elect upon rate harmonization.

11. Enbridge Gas recognizes that customers have options to switch rate classes and/or change their service options upon implementation of the rate harmonization plan. The rate harmonization plan offers customers choice, which increases the potential for rate class switching. As such, Enbridge Gas is proposing to establish the RHVA to be utilized from 2025 to 2028 to mitigate the uncertainty of customer choice on the forecast revenue upon the implementation of the rate harmonization plan. The proposed RHVA will record the material differences (in excess of $1 million in aggregate) to forecast revenue due to the implementation of the rate harmonization plan.

12. Rate harmonization is proposed to be implemented during the IR term, during which time Enbridge Gas's rates will be set through the proposed Price Cap mechanism. The Company is unable to adjust the volume forecast through the IR term to account for rate class switching until the Company's next rebasing in 2029. Enbridge Gas considered reflecting potential customer switching in the harmonized customer forecast but decided against this approach due to its subjective nature. Any changes to the customer forecast would require judgement, without prior customer experience or customer feedback on which to base the forecast. The Company recognized that if customer switching was reflected in the harmonized customer forecast and the customer switching did not materialize, the Company could earn more revenue or less revenue than the forecast used to set 2024 base rates. In lieu of adjusting the customer forecast, the Company is requesting the RHVA.

13. Enbridge Gas will record differences in forecast revenue in the RHVA based on customers that switch rate classes or change service options during the IR term.

The forecast revenue difference will be calculated based on the difference in the applicable monthly rates and charges applied to the customer parameters included in the 2024 Test Year Forecast. Differences in forecast revenue resulting from the addition or loss of customers during the IR term will not be recorded in the RHVA.

14. Enbridge Gas has assessed the causation, materiality, and prudence of the RHVA:
    a) Causation – The revenue variances in the proposed variance account are due to customers electing a different service option upon implementation of the rate harmonization plan than the assumption used to prepare the harmonized customer forecast. As such, the revenue variance is outside the base upon which the harmonized rates were derived.
    b) Materiality – The materiality of the revenue variance is unknown at this time but could materialize to an amount that would have a significant influence on the operation of the Company. Enbridge Gas recognizes the $1 million materiality threshold for the establishment of new accounts and proposes to record in the RHVA the total revenue variance that exceeds the materiality threshold on a cumulative basis during the IR term.
    c) Prudence – Any balance arising in the RHVA will be because of customer choice and outside the control of the Company. Enbridge Gas will provide detailed support for any amounts requested for clearance from the RHVA as part of the annual D&VA disposition proceedings.

3. Dawn Parkway Surplus Capacity Deferral Account (Account No. 179-323)

15. Enbridge Gas proposes to establish the Dawn Parkway Surplus Capacity Deferral Account (DPSCDA) to record actual revenue generated from the sale of all or a portion of the 89 TJ/d Dawn Parkway System surplus capacity forecast for the Winter 2023/2024. The Dawn Parkway System continuity, including the forecast surplus capacity, is provided at Exhibit 2, Tab 7, Schedule 1.

16. The full cost of the Dawn Parkway System is included in the 2024 Test Year revenue requirement. The Dawn Parkway System costs are recovered through the proposed rates for 2024 which are derived based on demands that are less than the full Dawn Parkway System capacity by 89 TJ/d. Enbridge Gas recognizes the surplus Dawn Parkway System capacity can have value if contracted for during the IR term. As a result, Enbridge Gas proposes to refund through the DPSCDA any revenue generated from the sale of the surplus capacity up to the 89 TJ/d per year. Based on the 2023 Rate M12 Dawn to Parkway demand rate, the maximum annual revenue that could be realized from the sale of the long-term firm surplus capacity is approximately $4 million[4] per year.

17. As part of Union's 2017 Dawn Parkway project[5], there was forecast surplus capacity of 30,393 GJ/d following construction of the project. Parties to the Settlement Agreement agreed that Union would include revenue associated with the sale of the surplus capacity in the associated deferral account.[6] Enbridge Gas proposes similar treatment for the Dawn Parkway System surplus capacity that is forecast as part of this Application.

18. The Dawn Parkway System surplus capacity of 89 TJ/d will be deemed to be sold long-term, in part or in whole, in any year if the Dawn Parkway System position for the forecast winter is in a surplus position of less 89 TJ/d. The new Dawn Parkway System contracted amounts will first be allocated to replace any turnback received during the year before it is allocated as a sale of the 89 TJ/d excess capacity from this Application. If any of the 89 TJ/d Dawn Parkway System surplus capacity is not sold on a long-term basis, Enbridge Gas will allocate a proportionate share of the

[4] Calculated at the 2023 Rate M12 Dawn to Parkway rate of $3.760/GJ/m x 89,000 GJ x 12 months.
[5] EB-2015-0200.
[6] EB-2015-0200, 2017 Dawn Parkway Project Settlement Proposal, November 13, 2015, p.8.

short-term transportation revenue generated through the sale of any remaining amount of the 89 TJ/d not deemed to be sold long-term to the DPSCDA.[7] Long-term and short-term revenue generated from the Dawn Parkway System capacity included in the DPSCDA cannot exceed 89 TJ/d on average for the year.

19. Enbridge Gas has assessed the causation, materiality, and prudence of the DPSCDA:
    a) Causation – The revenue that Enbridge Gas intends to record as a credit balance in the proposed DPSCDA is outside of the revenue forecast for the 2024 Test Year while the full costs of the Dawn Parkway System are in base rates.
    b) Materiality – The forecast revenue from the sale of the total amount of long-term firm surplus capacity can be up to $4 million per year which exceeds the $1 million materiality threshold for the establishment of new accounts.
    c) Prudence – The DPSCDA is designed to record as a credit balance revenue from the sale of up to 89 TJ/d forecast surplus capacity on the Dawn Parkway System. Any credit balance in the DPSCDA will result in a refund to the benefit of customers. Enbridge Gas will provide detailed support for the DPSCDA balance as part of the annual D&VA disposition proceedings.

4. Locate Delivery Services Variance Account (Account No. 179-324)

20. Enbridge Gas proposes to establish the Locate Delivery Services Variance Account (LDSVA) in response to Bill 93, the Getting Ontario Connected Act, which was recently passed into law on April 14, 2022[8]. The new regulations are expected to

[7] The inclusion of a proportionate share of short-term transportation revenue is consistent with the OEB Findings for the 2017 Dawn Parkway project deferral account at EB-2018-0105, Decision and Order, page 9.
[8] Bill 93, Getting Ontario Connected Act, 2022, amends Bill 8, the Ontario Underground Infrastructure Notification System Act, 2012 and Bill 257, the Building Broadband Faster Act, 2021.

cause significant changes to locate delivery services in Ontario. These changes are currently in development and as such, the locate delivery services costs included in the 2024 Test Year Forecast may not reflect the actual costs that will be incurred.

21. Enbridge Gas incurs costs to provide locate delivery services to its customers, as requested from customers, third-party contractors and other utilities. Enbridge Gas encourages customers to request locates prior to starting any ground disturbance activity in support of regulations[9] designed to preserve the safety of people, property, and the environment. Enbridge Gas has a duty to respond to locate requests that may affect underground infrastructure owned or operated by Enbridge Gas.

22. Enbridge Gas also anticipates it will incur costs from other utilities for locate delivery services provided to Enbridge Gas. The Company is required by law[10] to request locate services prior to starting any ground disturbance activity for its own operations. In response to Bill 93, other utilities are expected to start charging for locate delivery services and as a result, Enbridge Gas is expecting to incur incremental costs to request locate services from other third-party providers and other utilities for its own operations.

23. The 2024 Test Year Forecast includes $51 million of operating and maintenance /u
costs for external services to be incurred by Enbridge Gas to provide locate delivery services to customers and for receiving locate delivery services from other third-party providers and other utilities required for Enbridge Gas's own operations.
These costs exclude $7.5 million of internal company resources that provide /u

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[9] Ontario Underground Infrastructure Notification System Act, 2012 and the Canadian Energy Regulator Pipeline Damage Prevention Regulations – Obligations of Pipeline Companies.
[10] Ibid.

administrative support for the field locate process to respond to locate requests. Enbridge Gas expects the external costs for locate delivery services, including both the provision and receipt of required locate delivery services, to materially increase from the amounts included in the 2024 Test Year Forecast.

24. To help manage the incremental costs of locate delivery services, Enbridge Gas is proposing to introduce a new locate delivery service charge per locate request from third-party contractors and other utilities that require a field locate. The charge will not apply if Enbridge Gas receives a locate delivery request and there is no Enbridge Gas underground infrastructure within the area of the ground disturbance activity. A description of the proposed service charge is provided at Exhibit 8, Tab 3, Schedule 1.

25. To protect ratepayers and the Company from the cost uncertainty resulting from changes to locate service delivery and receipt requirements, Enbridge Gas is proposing to establish the LDSVA. The LDSVA will ensure that ratepayers only pay for, and Enbridge Gas only recovers, its actual incurred external costs for locates required to be delivered and received.

26. Enbridge Gas proposes that the LDSVA record the variance between the actual external costs for locate delivery services, and the external locate delivery costs included in base rates of $51 million. External locate delivery costs includes both the external costs to provide locate delivery services and receive locate delivery services for Enbridge Gas's own operations. The cost variance in the LDSVA will be offset by the revenue collected through the new locate delivery service charge applicable to third-party contractors and other utilities who request locate services from Enbridge Gas.

27. Enbridge Gas has assessed the causation, materiality, and prudence of the LDSVA:

a) Causation – Enbridge Gas has included a total of $51 million in the 2024 Test Year Forecast for external costs charged to Enbridge Gas for locate delivery services upon request from customers[11], third-party contractors and other utilities. Any amounts recorded in the LDSVA will reflect the actual costs incurred for the locate delivery services compared to the amounts included in rates, and as such, are outside the base 2024 Test Year Forecast. Enbridge Gas has also not included forecast revenue associated with the proposed new locate delivery service charge for third-party contractors. Any amounts collected from this charge will offset the cost variance in the LDSVA.

b) Materiality – Given the recent developing changes to the locate delivery services in Ontario, it's anticipated that the variance between the actual costs for locate delivery services, net of revenues, and the amount included in rates will exceed the $1 million materiality threshold for the establishment of new D&VAs.

c) Prudence – The costs to provide delivery locate services are reasonably incurred, as Enbridge Gas is required by law[12] to provide locate delivery services and request locate delivery services for its own operations to support preserving the safety of people, property, and the environment. Enbridge Gas will provide detailed support for the LDSVA balance as part of the annual D&VA disposition proceedings.

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[11] Occupants of residential and/or private property.

[12] Ontario Underground Infrastructure Notification System Act, 2012 and the Canadian Energy Regulator Pipeline Damage Prevention Regulations – Obligations of Pipeline Companies.

5. Open Bill Extension Deferral Account (Account No. 179-325) /u

28. Enbridge Gas proposes to establish the Open Bill Extension Deferral Account to record 100 percent of the net revenues for Open Bill services over a 10-month extension period from January 1, 2024, to October 31, 2024. A description of the Open Bill Access (OBA) Program is provided at Exhibit 1, Tab 14, Schedule 4. The Open Bill Extension Deferral Account is proposed to be in place for 2024, as the Open Bill Program will be wound down as of October 31, 2024.

29. The OBA Program provides other companies that sell energy-related products and services the ability to include their charges on Enbridge Gas's bill. Enbridge Gas made the decision to wind down the OBA Program effective October 31, 2024. The end date determination resulted from a consultation process with third-party billers (Billers) who use the OBA Program. Based on input and feedback from Billers, Enbridge Gas created a Transition Plan allowing for an optional 10-month extension to the original conclusion date of the program from December 31, 2023, to October 31, 2024.

30. As part of this Application, Enbridge Gas is proposing to extend the existing financial terms of the OBA Program for the extension period, with the only exception being that all of net revenues will be credited to ratepayers. If approved, the net revenue amounts applicable to the proposed account will be determined in accordance with the OEB-approved OBA Settlement Proposal[13] dated October 15, 2009, with updated Fees and Costs as determined in the 2014 OBA proceeding and adjusted each subsequent year[14].

[13] EB-2009-0043, OEB Decision, December 2, 2009.
[14] EB-2013-0099.

31. The existing Enbridge Gas OEB-approved Open Bill Revenue Variance Account (Account No. 179-48_) tracks the variance in the ratepayer share of Open Bill service net revenues, determined in accordance with OBA Program parameters, as compared to the amount included in rates. The new account will apply to the extension period, during which all net revenues will be credited to ratepayers. The Company is requesting the discontinuance of the existing Open Bill Revenue Variance Account effective January 1, 2024, in Exhibit 9, Tab 1, Schedule 4.

32. Enbridge Gas has assessed the causation, materiality, and prudence of the Open Bill Extension Deferral Account:
    a) Causation – There are no net revenues related to Open Bill services built into the 2024 Test Year Forecast. Any amounts recorded in the Open Bill Extension Deferral Account will reflect 100 percent of the net revenues earned for the Open Bill services, determined in accordance with the current OEB-approved approach. The account will not record any costs associated with winding down the OBA Program.
    b) Materiality – It's anticipated that net revenue for the extension period will result in an estimated ratepayer benefit that exceeds the $1 million materiality threshold for the establishment of new D&VA.
    c) Prudence – The OBA Program has been offered in its current form since the OEB's OBA[15] Decision, whereby revenues, net of costs, have been reviewed and approved by the OEB as part of annual D&VA disposition proceedings. The costs for the 10-month extension in this Account are consistent with the current OBA Program and will not include any expenses resulting from winding down the program. Enbridge Gas will provide detailed support for

[15] EB-2009-0043, OEB Decision, December 2, 2009.

the Open Bill Extension Deferral Account balance as part of the 2024 D&VA disposition proceeding.

6. Enhanced Distribution Integrity Management Program Deferral Account (Account No. 179-326) /u

33. Enbridge Gas proposes to establish the Enhanced Distribution Integrity Management Program (Enhanced DIMP) Deferral Account to record general administrative costs, as well as operating and maintenance and ongoing integrity inspection-related costs incurred to implement and execute the Enhanced DIMP. The Enhanced DIMP proposed by Enbridge Gas is in response to the OEB's St. Laurent Ottawa North Replacement Project Decision.[16] Further details on the Enhanced DIMP are provided at Exhibit 1, Tab 13, Schedule 3. The program will apply to a subset of distribution assets that are approaching end of life[17], and will ensure Enbridge Gas can thoroughly assess the condition of distribution pipeline assets to allow appropriate action to be taken, whether that is maintenance work or replacement of the pipe.

34. The costs included in the proposed deferral account will be amounts incurred to assess the primary risk for pipeline assets within the distribution system and to identify and prioritize assets that are approaching end of life to determine whether they need to be replaced. The program is intended to provide a substantive rigorous review of the condition of the assets to identify specific areas that could be subject to proactive mitigation to extend the life of the asset. Such solutions may be implemented to delay or avoid costly and time-consuming pipeline replacement projects. Should the review validate that the pipeline is approaching end of life, the

[16] EB-2020-0293, St. Laurent Ottawa North Replacement Project Decision, Section 3.1, page 16.
[17] The program will be limited to pipeline assets that are operating at pressures above 700 kPa, Nominal Pipe Size (NPS) of 6 or greater, over 1 kilometer in length, and greater than 50 years old.

Enhanced DIMP will allow the Company to further substantiate the necessity of its proposed leave-to-construct applications for reinforcement and integrity projects.

35. Enbridge Gas has assessed the causation, materiality, and prudence of the Enhanced DIMP Deferral Account:
    a) Causation – There are no expenses related to the program included in the 2024 Test Year Forecast. Any amounts recorded in the Enhanced DIMP Deferral Account will reflect the costs incurred to administer, implement, and execute the program.
    b) Materiality – It's anticipated that costs incurred will result in an estimated ratepayer expense of approximately $10 million annually, which includes the costs for inspections of Enhanced DIMP pipelines and additional resources to support the program. As such, the anticipated costs exceed the $1 million materiality threshold for the establishment of new D&VA.
    c) Prudence – The costs to execute the program are reasonably incurred, and will only contain the approved general administration, operations and maintenance, and inspection costs from the program. Enbridge Gas will provide detailed support for the Enhanced DIMP Deferral Account balance as part of the annual D&VA disposition proceedings.

7. Post-Retirement True-Up Variance Account (Account No. 179-328) /u

36. Enbridge Gas proposes to establish the Post-Retirement True-Up Variance Account (PTUVA) to record the difference between the revenue requirement impact of actual pension and other post-employment benefits (OPEB) costs and the revenue requirement impact of pension and OPEB costs included in rates.

37. The economic volatility experienced throughout 2022 resulted in significant /u
fluctuations in projected pension costs. Volatility and uncertainty in elements that

ultimately impact pension costs, such as inflation and interest rates, could persist through 2023 (and possibly beyond). To mitigate the risk of material changes in pension costs, Enbridge Gas is proposing to establish the PTUVA to protect both ratepayers and Enbridge Gas from revenue requirement variances between actual and forecast pension and OPEB accrual and cash-based amounts. The variance account would ensure Enbridge Gas recovers no more or less than the revenue requirement impact of actual pension and OPEB related amounts during each year.

38. Enbridge Gas has assessed the causation, materiality, and prudence of the /u
proposed PTUVA:

a) Causation – Any variances recorded in the proposed variance account will reflect the difference between the actual and 2024 Test Year Forecast pension and OPEB related revenue requirement. As such, this revenue requirement variance is outside the base upon which rates are derived.
b) Materiality – Given the volatility and uncertainty in economic and market conditions, it is anticipated that the difference between the actual pension and OPEB revenue requirement and the 2024 Test Year forecast amount included in rates will exceed the $1 million materiality threshold for establishment of new D&VAs.
c) Prudence – The proposed variance account ensures Enbridge Gas recovers no more and no less than the revenue requirement impact of actual pension and OPEB related amounts during the year.

TAB 2

MISCELLANEOUS SERVICE CHARGES

JEREMY GETSON, MANAGER ATTACHMENT SERVICES

JOSEPH DIMEO, SUPERVISOR COLLECTIONS

MICHAEL MCGIVERY, MANAGER DISTRIBUTION PROTECTION

IAN MACPHERSON, DIRECTOR DISTRIBUTION IN-FRANCHISE SALES

1. The purpose of this evidence is to request OEB approval of changes to miscellaneous service charges, effective January 1, 2024. Based on a review of the existing charges for the EGD and Union rate zones, Enbridge Gas is proposing to harmonize, eliminate, and establish new service charges to reflect the operations and services of the combined utility.

2. The miscellaneous service charges recover costs incurred by the utility for specific customer services, damage investigations and repair services. Recovering costs through miscellaneous service charges aligns cost incurrence with recovery based on the service provided. The other revenue generated from miscellaneous service charges offsets the costs incurred, thereby reducing the base delivery rates paid by all customers. The forecast revenue associated with these charges is provided at Exhibit 3, Tab 5, Schedule 1, with exception to the cut off at main charge and extra length charge (ELC), which are accounted for as a reduction to capital as detailed below.

3. The miscellaneous service charges form Rider G in the rate handbook, which is provided at Exhibit 8, Tab 2, Schedule 7, Attachment 1.

4. This evidence is organized as follows:
    1. Service Charges
    2. Damage Cost Recovery Charges

3. Custom Charges
4. Eliminated Charges

1. Service Charges

5. The purpose of service charges is to recover costs of specific service work performed by the utility for a customer. Recovering costs from the customer requiring the services alleviates the cost on all ratepayers as the nature of these costs relate to specific customer services. The cost of these services is incurred by the Company as O&M and/or capital expenditures, which is offset by the revenue generated from the specific service charges.

6. Enbridge Gas intends to harmonize all service charges for a simplified and consistent approach across all of Enbridge Gas's service areas. The service charges are set at fixed amounts as the cost per occurrence is generally consistent, this also simplifies the billing and collection of revenue.

7. To calculate each of the service charges, Enbridge Gas included the rate paid by the Utility for work provided by third-party contractors. The charges also include additional overhead costs such as planning and dispatch, supervision, and administration costs.

8. Most of the service charges were not reviewed in the 2013 Cost of Service proceeding for either EGD or Union, with the exception to the ELC which was updated as part of Union's 2013 Cost of Service. Given the length of time since the last review, the service charges no longer reflect the costs incurred by Enbridge Gas to provide the service.

9. The proposed charges are based on the 2024 Test Year. Enbridge Gas is proposing to apply the Price Cap Index (PCI) to the 2024 service charges[1] annually, consistent with other 2024 base rates. A description of the PCI calculation is provided at Exhibit 10.

10. The proposed charges are applicable to general service and contract customers, except for the ELC. The ELC is applicable to residential customers as described below.

11. Table 1 shows a summary of the current approved EGD and Union service charges and the proposed service charges. In addition to the service charges below, Enbridge Gas also charges custom amounts for damage response, damage remediation and ad-hoc customer requested services detailed in Section 3.

[1] With exception to the non-sufficient funds (NSF) charge and third-party costs since these charges are directly passed on to the customer.

Table 1
Summary of Current Approved and Proposed Service Charges

Line No.	Particulars ($)	Current Approved Charges EGD	Current Approved Charges Union	Proposed Charges
		(a)	(b)	(c)
1	New Account	25	35/38 (1)	25
2	Non-Sufficient Funds	20	20	20
3	Construction Heat Activation	70	-	120
4	Safety Inspection	70	-	120
5	Meter Unlock	70	35-65 (2)	120
6	Meter Dispute Test (3)	Varies	Varies	195
7	Extra Length Charge (per metre)	32	45	122
8	Locate Delivery Service	-	-	200

Notes:
(1) $35 for residential customers and $38 for non-residential customers in the Union rate zones.
(2) $35 for residential customers and $38 for non-residential for seasonal and $65 for non-payment for residential and non-residential customers in the Union rate zones.
(3) $105 for residential customers in the EGD rate zone and $50 for residential customers in the Union rate zones. Enbridge Gas charges non-residential customers in all rate zones a custom rate.

1.1. New Account

12. The new account charge is applied to customers when a new account is activated with Enbridge Gas. The new account charge is a one-time set up charge applicable to new accounts set up in new or existing premises, if a change in ownership or occupancy occurs.

13. Enbridge Gas currently charges for new account activation in the EGD and Union rate zones. In the EGD rate zone, Enbridge Gas charges a new account charge of $25 for residential and non-residential customers. In the Union rate zones, Enbridge Gas charges a connection charge of $35 for residential customers and $38 for non-residential.

14. Enbridge Gas is proposing to apply a new account charge of $25 for all customers to recognize that support is required to facilitate the process of activating new accounts. The $25 charge is based on 2024 Test Year Forecast costs and covers the administration costs incurred for the initial set up of a customer account which includes call centre resources used to update customer information and to activate billing information. In certain instances, a site visit may be required at the premise.

1.2. Non-Sufficient Funds (NSF) Charge

15. NSF charges occur when customers who pay their bills through automatic withdrawal or by cheque do not have sufficient funds in their account to cover the amount owed on their invoice. The NSF charge recovers the amount Enbridge Gas is charged from the financial institution. The costs incurred by Enbridge Gas are directly passed through to the customers.

16. Enbridge Gas is not proposing to change the NSF charge. Enbridge Gas currently charges $20 per NSF occurrence in the EGD and Union rate zones and proposes to continue passing that charge to the customer.

1.3. Construction Heat Activation

17. Construction heat activation is the temporary use of natural gas for buildings under construction, which is generally requested by builders and installers before the building is occupied and before a safety inspection is completed.

18. The construction heat activation service charge is intended to recover the cost incurred per occurrence (site visit) for construction heat meter activation when the request is not made through the online application portal. If the request for construction heat activation is completed through the online application portal, then the meter will be turned on at the time it is installed, and a separate site visit is not

required. The service fee applies to the builder or installer that requests the service for both residential and non-residential services.

19. Enbridge Gas recovers the cost to provide the activation service through a service charge because the costs are only incurred if the online application portal is not used to make the request.

20. Enbridge Gas currently charges $70 for the construction heat activation services in the EGD rate zone for residential and non-residential customers and does not charge for this service in the Union rate zones.

21. Enbridge Gas is proposing to increase the charge to $120 per occurrence for construction heat activation services. This charge includes services for both residential and non-residential customers located in all Enbridge Gas service areas. The proposed charge is based on 2024 Test Year Forecast costs and includes third-party contractor charges to provide this service plus incremental overhead costs. The proposed charge is greater than the current charge in the EGD rate zone for construction heat activation services, as the previous charges have not been updated in over 10 years and no longer reflect the cost to provide the service.

1.4. Safety Inspection

22. A safety inspection occurs when gas is first introduced at a premise or when gas is reintroduced at a premise.

23. When gas is first introduced and appliances are activated for the first time, an initial safety inspection[2] is required for all new homes and businesses. The intention of

[2] Referred to as an initial putting into use inspection, per Technical Standards and Safety Act, 2020. Ontario Regulation 212/01 Gaseous Fuels.

the inspection is to check for compliance with all applicable policies, standards, and procedures. A premise cannot be occupied until the inspection has been completed. There is no charge for the initial safety inspection. If the initial safety inspection is deemed unacceptable and subsequent inspections are required, a charge will occur for each inspection. Subsequent visits would result in a safety inspection charge to recover incremental costs incurred resulting from the customer's non-compliance in ensuring a safe premise.

24. When gas is reintroduced at a premise, a safety inspection must be performed to review the condition of appliances and to check for compliance with all applicable policies, standards, and procedures. Reintroducing gas typically occurs after a service disruption or when work is completed at the premise. All safety inspections related to reintroducing gas at the premise will be subject to a safety inspection charge unless the service disruption or the work is initiated by Enbridge Gas.

25. Enbridge Gas currently charges $70 for safety inspection services (previously called inspection or inspection reject) for residential and non-residential customers in the EGD rate zones and does not charge for the service in the Union rate zones.

26. Enbridge Gas is proposing to increase the charges to $120 for safety inspection services per occurrence. These charges include services for both residential and non-residential customers located in all Enbridge Gas service areas. The proposed charge is based on 2024 Test Year Forecast costs, including third-party contractor charges to provide the service plus incremental overhead costs.

27. The proposed charges are increasing compared to the current charges in the EGD rate zone, as the current charges have not been updated in over 10 years and no longer reflect the cost to provide the service.

1.5. Meter Unlock

28. The meter unlock service is the action of turning the meter on after deactivation to reconnect the customer to gas service. This service requires sending a gas technician to the premise. In addition to turning the meter on, the gas technician will also perform a safety inspection of the premise prior to reactivation of gas service.

29. The meter unlock service charge is intended to recover the cost incurred per occurrence (site visit) for a meter unlock service. The meter unlock charge is applicable to existing[3] residential and non-residential customers. Enbridge Gas applies the charge to customers requesting the meter unlock service for seasonal use or due to nonpayment of regular monthly bills.

30. Enbridge Gas currently charges for meter unlock services in the EGD and Union rate zones. In the EGD rate zone, Enbridge Gas charges $70 to unlock meters for seasonal for non-residential customers and for pool heaters for residential customers and does not charge for non-payment. In the Union rate zones, Enbridge Gas charges $35 for residential customers and $38 for non-residential customers for seasonal and $65 for non-payment for both residential and non-residential customers.

31. Enbridge Gas is proposing to increase the charge to $120 for meter unlock service per occurrence to reflect the costs to provide the service, including third-party contractor charges and overhead costs. This charge is applicable for all meter unlock services for residential and non-residential customers located in all Enbridge Gas service areas, including seasonal and non-payment customers. The proposed charge is based on 2024 Test Year Forecast of costs, including third-party contractor charges to provide the service plus incremental overhead costs.

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[3] New customers are charged a new account charge as described in Section 1.1.

1.6. Meter Dispute Test

32. A meter dispute test occurs when a customer disputes the accuracy of a meter. Enbridge Gas exchanges the meter with a replacement meter and sends the disputed meter to Measurement Canada for an independent performance test.

33. The meter dispute test charge is intended to recover the cost per occurrence for each meter dispute test conducted for both residential and non-residential customers. The service charge is only applied if Measurement Canada determines the meter is performing correctly.

34. Enbridge Gas currently charges for the meter dispute test services in the EGD and Union rate zones. In the EGD rate zone, Enbridge Gas charges $105 to complete a meter dispute test for residential customers and charges a custom amount based on the costs to provide the service for non-residential customers. In the Union rate zones, Enbridge Gas charges $50 to complete a meter dispute test for residential customers and charges a custom amount based on the costs to provide the service for non-residential customers.

35. Enbridge Gas is proposing to charge $195 for meter dispute test services per occurrence. This charge is applicable for services for both residential and non-residential customers located in all Enbridge Gas service areas. The proposed charge is based on 2024 Test Year Forecast costs and includes third-party contractor charges to provide this service plus incremental overhead costs.

36. Enbridge Gas is proposing to set a common charge for both residential and non-residential customers, as there is no material difference in the work required by the Company to provide the service for non-residential customers. A common service charge based on a set amount also provides more price certainty for non-residential

customers, should they request this service. The proposed charge is greater than the current charges in the EGD and Union rate zones for meter dispute test services for residential customers because the previous charges have not been updated in over 10 years and no longer reflect the cost to provide the service. The proposed charge may be lower than the current custom charge for some non-residential customers depending on specific customer circumstances.

1.7. ELC[4]

37. Enbridge Gas uses the extra length rule to assess feasibility of residential infill[5] customers. Currently, the rule assumes standard residential services are economically feasible to a threshold length of 20 metres for the EGD rate zone and 30 metres for the Union rate zones. Customers pay an ELC when the service length exceeds these thresholds. The current approved ELC is $32 per additional metre for the EGD rate zone and $45 per additional metre for the Union rate zones. Despite increases in construction costs, these ELC rates have remained constant for many years and require updating to reflect the latest marginal cost per metre. The ELC collected is accounted for as a reduction to capital investment or a credit to assets.

38. Enbridge Gas is proposing a harmonized service length threshold of 20 metres and an updated ELC of $122 per additional metre that will apply consistently across all franchise areas. Service length threshold and ELC have been determined in consideration of various factors including results from the customer engagement and internal data analysis as described below. The customer engagement showed that customers had varying preferences when considering the options presented (of

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[4] Charge was previously called street service alteration on Rider G.
[5] Residential infills are existing homes which are converting from other fuel types to natural gas to meet their energy needs.

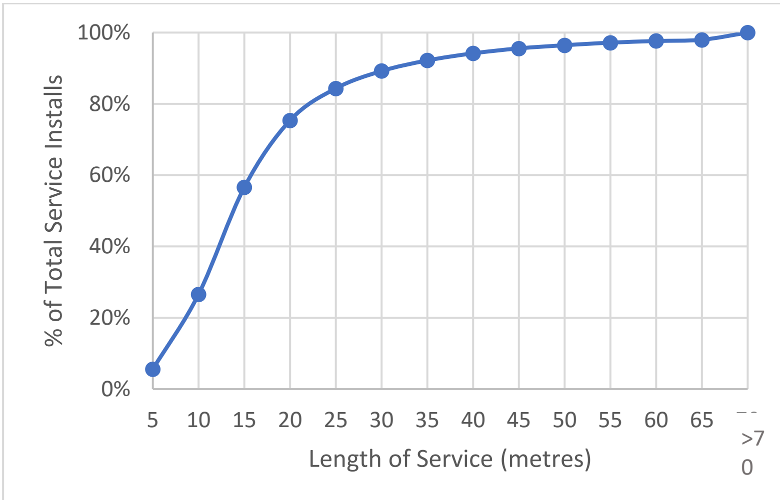
a shorter or longer length for the service length threshold and associated ELC), with no strong preference for one option. Approximately one third of customers (32%) indicated a preference of 15 metres with a lower ELC, a combined 35% indicated a preference of 20 metres (22%) or 25 metres (13%) with a higher ELC, and the remaining 32% had no preference or indicated don't know. Further details can be found in the customer engagement report provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 279-280.

Proposed Service Length Threshold

39. Enbridge Gas is proposing that residential infill customers be provided with the first 20 metres of service at no cost. The length of the service will be measured from the customer's property line to the location where the gas meter is installed. Service lengths beyond the threshold length of 20 metres will be subject to the ELC.

40. The proposed service length threshold is based on data from residential infill services installed between 2018 to 2020. Based on this data, it was determined that the distribution revenue from a typical residential customer can support the average cost of services below 20 metres. As shown in Figure 1, approximately 75% of residential services are less than or equal to 20 metres. As such, the proposed service length threshold will result in the Company attaching most infill services with no accompanying ELC. This anticipated outcome will support continued efficiencies in the infill service attachment process while also ensuring no undue cross-subsidization.

Figure 1: Residential Service Length by % of Total Service Installs, 2018 to 2020

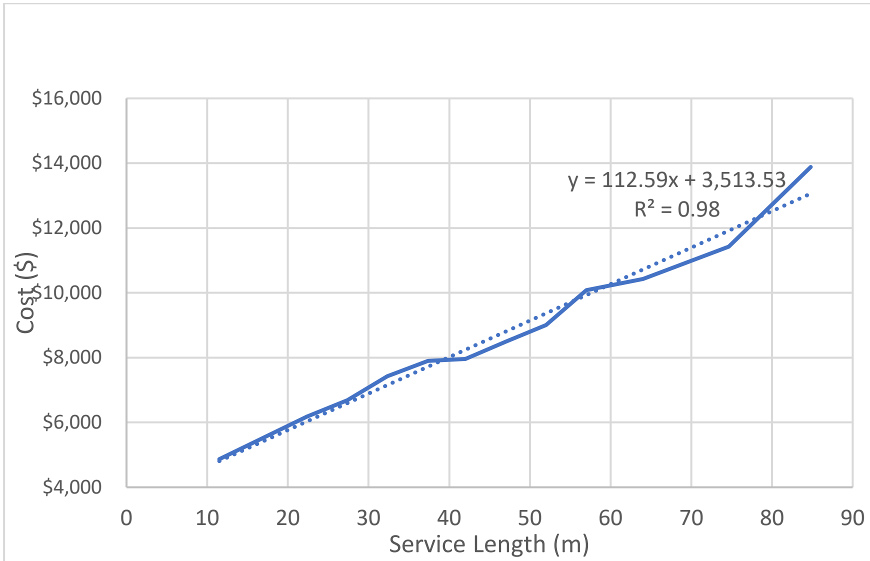


Proposed ELC

41. Enbridge Gas is proposing an ELC of $122 per metre in excess of the 20-metre service length threshold. The ELC of $122 per metre in 2024 has been calculated based on the actual cost of $113 per metre established for 2020, as described in this section of evidence, escalated for annual inflation of 2%.

42. The ELC of $113 per metre (for 2020 prior to inflation), represents the marginal cost per metre and was determined through a linear regression of historical service costs vs. service length, as shown in Figure 2. The regression analysis was conducted using actual service lengths and costs over the 3-year period from 2018 to 2020, across all rate zones. The equation of the regression trend line (y=113x + 3514) in Figure 2 indicates two cost components; 1) the slope of the line that is $113 represents the marginal (or variable) cost per metre and 2) fixed cost is $3,514. The regression results indicate a strong correlation between cost and length, as evident from a high R-squared (0.98) value.

Figure 2: Average Service Cost, 2018 to 2020



43. The proposed cost per metre for ELC is higher compared to the current EGD and Union ELC because the charges have not been updated in over 10 years. Since then, construction costs have increased due to various factors including inflation, enhancement in safety standards, extensive use of trenchless technology, sewer safety and cross bore mitigation requirements, and additional costs related to municipal permit fee and restoration requirements.

1.8. Locate Delivery Service Charge

44. Enbridge Gas currently provides locate delivery services upon request from customers[6], third-party contractors and other utilities at no extra charge.

45. Bill 93, the Getting Ontario Connected Act, 2022[7], was recently passed into law on April 14, 2022. Bill 93 imposes significant changes to how locates are delivered in

[6] Occupants of residential and/or private property.
[7] Bill 93, Getting Ontario Connected Act, 2022, April 14, 2022. https://www.ola.org/sites/default/files/node-files/bill/document/pdf/2022/2022-04/b093ra_e.pdf

Ontario. Bill 93 amends Bill 8, the Ontario Underground Infrastructure Notification System Act, 2012[8] and Bill 257, the Building Broadband Faster Act, 2021[9].

46. As an outcome of Bill 93, Enbridge Gas:
    a) Will experience increased regulatory requirements related to the timelines for completing locate requests;
    b) Expects that the number of locate delivery requests will increase;
    c) Will become subject to administrative penalties for non-compliance in the event the Company cannot meet the timelines for completion of locate requests;
    d) Expects that the cost per locate will increase due to the need for incremental resources to meet the timelines to complete field locates; and
    e) Expects other utilities to charge for locate delivery services, increasing the Company's costs.

47. In response, Enbridge Gas is proposing to introduce a new charge of $200 per locate request from third-party contractors and other utilities that require a field locate. The charge will not apply if Enbridge Gas receives a locate delivery request and there is no Enbridge Gas underground infrastructure within the area of the ground disturbance activity. The intent of the charge is to ensure that the costs to provide the locate delivery services to third-party contractors and other utilities are recovered from the third-party contractors and other utilities requesting the service and not borne by customers.

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[8] Bill 8, Ontario Underground Infrastructure Notification System Act, 2012, June 19, 2012. https://www.ola.org/sites/default/files/node-files/bill/document/pdf/2012/2012-06/bill---text-40-1-en-b008ra.pdf

[9] Bill 257, Supporting Broadband and Infrastructure Expansion Act, April 12, 2021. Bill 257, Supporting Broadband and Infrastructure Expansion Act, 2021 - Legislative Assembly of Ontario (ola.org)

48. Enbridge Gas is not proposing a service charge for locate requests from customers involving ground disturbance activities at their residential and/or private properties, as these costs will continue to be recuperated through delivery rates. Projects completed by customers involving ground disturbance activities at residential and/or private properties are typically small in scale and cost (i.e. basic personal property landscaping), relative to third-party contractor projects. Additionally, having a charge for locate services for projects completed at residential and private properties by customers may deter these customers from requesting locates, which poses a safety and operational risk. By not charging these customers for locate requests, Enbridge Gas will continue to encourage these customers to request locates prior to starting any ground disturbance in support of preserving the safety of people, property, and the environment.

49. Given that the new regulations are expected to cause significant changes to the locate delivery services, Enbridge Gas is proposing a new locate delivery service variance account to protect customers and the Company from the cost uncertainty in 2024 and beyond, as provided in Exhibit 9, Tab 1, Schedule 3. Enbridge Gas has not included revenue from the locate delivery service charge in the 2024 Test Year Forecast. Any amounts collected will be recorded in the proposed variance account.

Background

50. Enbridge Gas has a duty to respond to locate requests made with regard to proposed ground disturbance activity that may affect underground infrastructure owned or operated by Enbridge Gas, as per the Ontario Underground Infrastructure

Notification System Act, 2012[10] and the Canadian Energy Regulator Pipeline Damage Prevention Regulations – Obligations of Pipeline Companies[11].

51. As a result of these regulations, Enbridge Gas has received an average of 1,135,000 locate requests annually for the period of 2019 to 2021 with 70% to 80% of annual requests being placed by third-party contractors and other utilities. The remainder of requests each year are placed by customers for private properties and Enbridge Gas.

52. In response to each locate request, Enbridge Gas provides:
    a) A written statement outlining that none of Enbridge Gas's underground infrastructure are within the area of the ground disturbance activity, or
    b) A field locate, which is composed of:
        i. Markings on the ground of the location of Enbridge Gas underground infrastructure using electromagnetic locating equipment; and
        ii. A written document containing information in regard to the location of Enbridge Gas underground infrastructure.

53. As part of the response to certain locate requests, Enbridge Gas will require administrative and/or in-field safety controls to prevent damage of Enbridge Gas assets in alignment with the goal of preserving the safety of people, property, and the environment.

[10] Government of Ontario. (2022, April, 14). Ontario Underground Infrastructure Notification System Act, 2012, S.O. 2012, c. 4. https://www.ontario.ca/laws/statute/12o04
[11] Government of Canada. (2020, March, 16). Canadian Energy Regulator Pipeline Damage Prevention Regulations – Obligations of Pipeline Companies (SOR/2016-133). https://laws-lois.justice.gc.ca/eng/regulations/SOR-2016-133/index.html

54. Safety controls on locates are based on various categories and features of underground infrastructure that may be directly within the proposed excavation area and/or the nearby vicinity. Examples of safety controls include Enbridge Gas:
    a) Completing reviews of additional records;
    b) Requiring that third-party contractors and other utilities obtain permits from Enbridge Gas;
    c) Providing in-field observation of the third-party contractor's and other utilities' excavation; and/or
    d) Completing periodic leak surveys of underground infrastructure.

55. Since the applicable locate regulations under the Ontario Underground Infrastructure Notification System Act came into effect in 2012, Enbridge Gas has borne all costs related to delivering locates to third-party contractors and other utilities as operating expenses, including the completion of safety controls and all associated internal management staff. Rationale for this approach has primarily been to remove barriers to third-party contractors and other utilities, for requesting locates to help prevent Enbridge Gas asset damages by third-party contractors and other utilities until the excavation community within Ontario has matured to the point of achieving compliance with regulations, which requires excavators to obtain utility locates before excavating.

56. Bill 93 increases the emphasis on utilities to meet compliance requirements for locate delivery which is subsequently necessitating significant investment and enhancements to be implemented by Enbridge Gas.

Proposed Locate Delivery Charge

57. In response to Bill 93, Enbridge Gas is proposing that the OEB approve a new service charge of $200 for each locate request received from third-party contractors and other utilities that require a field locate by an Enbridge Gas resource.

58. The rationale for charging third-party contractors and other utilities for Enbridge Gas's services related to their locate requests is to;
    a) Ensure costs are recovered from third-party contractors and other utilities requesting the service and not borne by Enbridge Gas customers; and
    b) Help offset the significant incremental costs Enbridge Gas will incur to comply with the new regulations.

59. Table 2 shows a summary of the proposed charges for Enbridge Gas's completion of each locate request from third-party contractors and other utilities. The proposed charge is designed to recover Enbridge Gas's costs of providing the locate delivery service.

Table 2
Proposed Locate Delivery Service Charge Per Locate Request

Line No.	Particulars ($)	Proposed Charge
		(a)
1	Field Locate Delivery	160
2	Locate Delivery Administration	10
3	Field Locate Safety Controls	30
4	Total Proposed Charge Per Locate Request	200

Field Locate Delivery

60. When a locate request is made for a field locate, an Enbridge Gas second party representative (locator) must be dispatched to the third-party contractor's or other utilities' proposed ground disturbance location. The locator will then mark the ground with the location of Enbridge Gas underground infrastructure using electromagnetic locating equipment and develop documents containing information

in regard to the location of Enbridge Gas underground infrastructure as per provincial industry standardized and approved utility locate practices.

61. As locate requests by third-party contractors and other utilities have grown more complex and extensive over recent years and the emphasis on utilities to meet compliance requirements of five business days for locate delivery have increased, resources for completing field locates have become strained. As a result of limited resources, Enbridge Gas is facing significant challenges including increased workload on each locator, difficulty hiring locators and difficulty retaining locators. To address these challenges, Enbridge Gas is working with industry stakeholders to increase compensation to locate service providers. The increase in compensation also recognizes the level of liability on the part of locators in delivering locate services.

62. As a result of these efforts, the average cost per locate is expected to rise to approximately $160 per locate starting in 2023, up from approximately $65. The majority of the increase will be passed directly to the frontline personnel resources completing field locates. This will better align the compensation within the utility locate industry to that of skilled construction industry labour and is expected to improve resourcing.

63. In addition, field locate delivery includes notification charges by the provincially mandated regional utility one call service provider, which is included in the assumptions arriving at the average annual cost per locate of approximately $160.

Locate Delivery Administration

64. In order to support Enbridge Gas's end-to-end field locate processes related to responding to third-party contractor and other utilities' locate requests for ground

disturbance, Enbridge Gas maintains a dedicated full-time department of managerial and clerical administrative employees. This department is staffed by over 40 employees with up to an additional ten contractors that are retained on a seasonally variable basis.

65. Administrative employee support field locate processes through multiple means including:
    a) Services to manually review locate requests to determine when field locates are not required as Enbridge Gas assets are not in the locate area;
    b) Assisting locators through in-office and/or in-field services;
    c) Completing quality management reviews;
    d) Reviewing industry performance metrics and addressing industry trends;
    e) Coordinating with locators on workload forecasts and prioritization;
    f) Coordinating with third-party contractors and other utilities to manage requests; and
    g) Ensuring quality and accuracy of locates through quality control program.

66. Collectively all permanent and contract managerial and clerical administrative employees, in addition to associated administrative non-personnel operating expenses has an average administrative cost per locate of approximately $10.

Field Locate Safety Controls

67. Various resources, processes and procedures are required to maintain safety controls on locates based on various categories and features of underground infrastructure within the proposed excavation area.

68. For each locate request requiring additional safety controls, a combination of Enbridge Gas internal labour resources and Enbridge Gas contractor resources will

be engaged in advance and during the ground disturbance activities of third-party contractors and other utilities. These resources are required to ensure that the third-party contractors and other utilities are following all of Enbridge Gas's ground disturbance requirements and maintaining appropriate physical separation from Enbridge Gas assets.

69. Based on the average resource requirements of each locate requiring safety controls, the average cost per locate is approximately $30.

2. Damage Cost Recovery Charges

70. The purpose of damage cost recovery charges is to recover costs incurred by the Utility to remediate assets damaged by third-party activities. Enbridge Gas is requesting approval of changes to the damage cost recovery charges for at fault damages to Enbridge Gas assets by external parties. Enbridge Gas has existing processes in the EGD and Union rate zones to recover costs associated with damages. Remediation costs for each damage are initially incurred by Enbridge Gas as expenses, which are offset by charging the party at fault once all remediation work is complete.

71. Damages to Enbridge Gas assets caused by third-party activities pose an ongoing risk to the safe and reliable delivery of natural gas in the province. Damages not only cause network service disruptions to customers whose lives and livelihoods depend on the delivery of natural gas, but also:
   a) Pose health and safety risks to property and lives in the surrounding area, especially in the rare instance of an ignition;
   b) Pose a risk of environmental damage in the form of hydrocarbons entering the atmosphere due to fugitive emissions; and

c) Undermine scheduled operations to maintain the integrity of Enbridge Gas's assets by unexpectedly diverting resources on an emergency priority basis.

72. Significant efforts are undertaken by Enbridge Gas to help prevent damages, but despite these efforts, there are approximately two to three thousand damages to Enbridge Gas assets every year caused by third-party activities, which are primarily due to ground disturbances. Examples of these preventative efforts include programs pertaining to; locate delivery, pipeline patrols to detect and intervene upon unauthorized third-party activities, educating third parties about safe excavation practices and requirements, and proactive engagements of excavators at sites posing heightened risks of damages.

73. Enbridge Gas responds to each damage on an emergency priority and does not cease operations until the situation is made safe, and the damage is fully remediated. As part of responding to these damages on an emergency priority basis, Enbridge Gas requires the involvement of multiple company and contracted resources.

74. The proposed damage charges are based on negotiated rates between Enbridge Gas and contracted service and/or material providers involved in damage response. The charges have been identified based on commonly encountered categories of costs associated with the remediation of damages. The cost recovery amounts collected for at fault damages is recorded as other revenue.

75. Table 3 shows a summary of the current approved damage charges for the EGD and Union rate zones compared to the Enbridge Gas proposed charges. A description of each charge is provided below. The combination of charges for each damage as invoiced are unique to each damage based on the required

remediation. In addition to the damage cost recovery charges identified below, Enbridge Gas also has custom charges for a variety of services where the work and the associated costs are not consistent, as detailed in Section 3.

Table 3
Summary of Current Approved and Proposed Damage Cost Recovery Charges (1)

Line No.	Particulars ($)	Current Charges EGD	Current Charges Union	Proposed Charge
		(a)	(b)	(c)
1	Emergency crew response (2)	-	-	290
2	Damage investigation	420	-	550
3	Loss of containment (gas loss)	Flat rates or specific calculation based on duration and pipe size	$0.10/ standard cubic metre of gas lost	No charge, flat rates or specific calculation based on duration and pipe size

Notes:
(1) Actual damage charge recoveries can be subject to litigation and dispute processes, including court orders and settlements.
(2) New charge proposed.

2.1. Emergency Crew Response

76. Emergency crew response work accounts for the redirecting of resources from active field sites of planned Enbridge Gas work to an incident of active damage. The emergency crew response charge is applicable to all damages.

77. Enbridge Gas is proposing a new charge of $290 per damage for emergency crew response to recover the incremental costs incurred by Enbridge Gas to demobilize and remobilize resources from active field sites, which includes stopping work, securing the work site and travelling to the new site under an emergency priority. Once the damage has been remediated, the resources need to be remobilized,

which includes travelling back to the original work site and resuming previously halted work.

2.2. Damage Investigation

78. Damage investigation accounts for the resources dispatched to analyze the damage and determine the root cause. The damage investigation charge is applicable to all damages.

79. Enbridge Gas currently charges $420 per damage in the EGD rate zone and does not charge for this service in the Union rate zones.

80. Enbridge Gas is proposing to charge $550 for all damage investigations. The proposed charge of $550 per damage is based on the existing average total cost of contract resources dispatched to analyze the damage in addition to the cost of one hour of an Enbridge Gas internal resource. The function of the Enbridge Gas resource for this activity is to conduct an audit of the contractor's results in addition to completing all necessary investigation submissions and correspondence with regulators and the excavator involved in the damage.

2.3. Loss of Containment (Gas Loss)

81. Loss of containment accounts for the value of natural gas fugitive emissions lost to the atmosphere caused by the damage.

82. Enbridge Gas currently charges a flat rate or a custom charge per damage based on the loss of containment duration and pipe size in the EGD rate zone. Enbridge Gas charges a variable charge of $0.10/m^3$ of gas lost in the Union rate zones.

83. Enbridge Gas is proposing to charge for loss of containment based on the pipeline diameter (in nominal pipe size (NPS)), operating pressure class and time duration of the fugitive emissions, similar to the approach used in the EGD rate zone. The determination of the proposed charge mechanism is outlined in Table 4.

Table 4
Summary of Damage Loss of Containment (Gas Loss) Cost Recoveries Charge

Line No.	Loss of Containment Duration	0 to 15 minutes	16 to 45 minutes	46 to 180 minutes	Over 180 minutes
		(a)	(b)	(c)	(d)
1	NPS 1/2 IP NPS 1/2 HPPE	No charges	Flat rate	Flat rate	Specific calculation
2	NPS 1/2 MP	No charges	No charges	Flat rate	Specific calculation
3	NPS 1 LP NPS 1- 1/4 LP NPS 3/8 LP NPS 3/8 MP NPS 3/8 IP	No charges	No charges	No charges	Specific calculation
4	NPS 2 LP	No charges	No charges	Specific calculation	Specific calculation
5	All other pipeline assets	Specific calculation	Specific calculation	Specific calculation	Specific calculation

Abbreviation
HPPE Higher Pressure Polyethylene
IP Intermediate Pressure
LP Low Pressure
MP Medium Pressure

84. In some cases, there are no charges depending on the pipe diameter and the pressure. There is insufficient loss of containment or damages to require a charge.

85. In certain cases, the specific calculation is based on the rate of release and duration of release under the conditions of the distribution system at the time of damage, using modelling software. The amount calculated to be released is applied to the reference price for each respective rate zone.

86. In some instances, a flat rate charge will be applied. The applicable flat rate charges vary based on operating pressure and time duration of fugitive emissions, as provided at Table 5.

Table 5
Summary of Proposed Damage Loss of Containment (Gas Loss) Flat Rate Charges

Line No.	Pressure Category (1)	16 to 30 minutes	31 to 45 minutes	46 to 60 minutes	61 to 75 minutes	76 to 90 minutes	91 to 105 minutes	106 to 180 minutes
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	MP	$0.00	$0.00	$10.00	$15.00	$20.00	$25.00	$25.00
2	IP	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00
3	HPPE	$15.00	$35.00	$50.00	$70.00	$90.00	$105.00	$125.00

Note:
(1) Not applicable when the pipeline asset has an excess flow valve upstream of the damage location.

87. These flat rate charges are not applicable when the pipeline asset has an excess flow valve upstream of the damage location as the excess flow valve halts any escape of gas when the mechanism is triggered by the conditions of a release.

3. Custom Charges

88. Custom charges recover the costs incurred per occurrence for a variety of services where the work and the associated costs are not consistent. The costs to provide the service can vary and the set charges described in Section 1 and Section 2 of this evidence would not be appropriate for these services. Custom charges are applicable in certain instances of damage response, damage remediation and ad-hoc customer requested services.

89. A custom charge is determined on a case-by-case basis and could include internal labour (regular and/or overtime), third-party invoices, and/or materials. Custom

charges are based on costs incurred by Enbridge Gas and passed through to the customer.

90. Listed below are examples where Enbridge Gas would apply a custom charge as a result of varying costs associated with the service provided:
    a) Fitter first response accounts for the certified gas fitter resources dispatched as a primary responder to a damage. The proposed charge is calculated as the total fitter time multiplied by the applicable regular work hour labour, overtime labour, and/or contractor labour charges, as applicable;
    b) Damage re-light accounts for resources associated with returning service to customer appliances following a damage repair. Enbridge Gas is proposing a custom charge for damage relight that is calculated as the total fitter time multiplied by the applicable regular labour, overtime labour, and/or contractor labour charges, as applicable; and
    c) Service line alterations account for changes and moves of an existing service line or a meter without adding new services. The alterations typically vary in length and the custom charge is based on the length of the move.

91. Enbridge Gas currently uses custom charges to recover costs associated with labour, overtime, materials and third-party invoices to provide customer specific services in both the EGD and Union rate zones.

92. Table 6 details the various components to calculate custom charges.

Table 6
Summary of Current and Proposed Custom Charges

Line No.	Particulars ($)	Current Charges EGD (a)	Current Charges Union (b)	Proposed Charges (c)
1	Regular Labour (per hour)	140	137 (1)	178
2	Overtime Labour (per hour)	175	188 (1)	223
3	Third Party Invoices	Third-party invoice costs	Third-party invoice costs	Third-party invoice costs
4	Materials	Material costs	Material costs	Material costs

Note:
(1) The regular and overtime labour charges are updated on an annual basis in the Union rate zones, these rates are based on the 2022 year. The charges could also vary based on the work performed.

3.1. Regular Labour

93. The regular labour charge is used to derive custom charges for Enbridge Gas when internal company resources are used during regular work hours to provide services such as damage response, damage remediation, street service alterations and other ad-hoc customer requested services.

94. Enbridge Gas currently charges for labour during regular work hours in the EGD and Union rate zones. In the EGD rate zone, Enbridge Gas currently charges $140 per hour as found in Rider G of the handbook. The regular labour charge was last updated in 2009. In the Union rate zones, the regular labour charge is $137 per hour, and is updated on an annual basis.

95. Enbridge Gas is proposing to set the regular labour charge during regular work hours at $178 to reflect the costs for labour. For any time spent on premise that is below the full hour, the full hourly rate will apply. To calculate the regular labour

charge, Enbridge Gas included the average cost for unionized employees, including salary, pension and benefit costs. This rate also includes overhead costs such as planning and dispatch, supervision, fleet, and administration costs.

3.2. Overtime Labour

96. The overtime labour charge is used to derive custom charges for Enbridge Gas internal labour resources for overtime work hours required to provide services such as damage response, damage remediation, street service alterations and other ad-hoc customer requested services.

97. Enbridge Gas currently charges hourly for overtime labour in the EGD and Union rate zones. For any time spent on premise that is below the full hour, the full hourly rate will apply. In the EGD rate zone, Enbridge Gas charges $175 per overtime labour hour which is 1.25 times the regular labour charge. In the Union rate zones, Enbridge Gas charges $188 per hour.

98. Enbridge Gas is proposing to set the hourly overtime labour charge at 1.25 times the regular work hours labour rate ($178 x 1.25 totalling $223 per hour) for any services rendered by Enbridge Gas internal labour resources working outside of regular work hours. The overtime premium of 1.25 times the regular labour charge is based on the fully loaded cost of the employee (i.e. base pay, overtime rates and policies, etc.) according to current policies for associated internal labour resources working under overtime conditions.

3.3. Third-Party Invoices

99. Enbridge Gas is proposing to continue to charge the cost invoiced by the third-party for the specific services that are being custom billed. This approach is consistent with the current recovery of third-party charges in the EGD and Union rate zones.

3.4. Materials

100. Enbridge Gas is proposing to continue to charge a materials charge to account for the value of materials used for any work recovered through a custom charge to recover the cost of materials.

101. Damages to pipelines smaller than NPS 4 are proposed to have a material cost of $35 applied that is based on the average of historical damages for damages to pipes smaller than NPS 4. Damages to pipelines NPS 4 and greater are proposed to have a material cost specific to the damage’s repair cost applied.

4. Eliminated Charges

102. Enbridge Gas proposes to simplify administrative processes by reducing the number of service charges and including the service charges that are frequently used and easy for customers to understand. The eliminated charges collected in other revenue in 2021 are minimal, with less than $0.05 million cumulative impact for all the eliminated services. Eliminating cut off at main charges, which are not a part of other revenue, results in an increase to rate base of approximately $5 million.

103. Although the service charge is eliminated, Enbridge Gas will continue to offer the service to the customer where required without charge. The eliminated service charges are provided at Table 7. A description of each eliminated service is provided below.

Table 7
Summary of Service Charges - Eliminated

Line No.	Particulars ($)	Current Charges EGD (a)	Union (b)
1	Lawyer Letter Handling	15	-
2	Request for Service Call Information	30	-
3	Duplicate Bills (Manual processing)	-	15
4	Detailed Billing Analysis/Statement of Account	10	Varies (1)
5	Valve Lock	135-280	-
6	Removal of Meter	280	-
7	Meter Lock	70	22 (seasonal)
8	Meter in/out	280	-
9	Cut off at Main (Residential)	1,300	-
10	Cut off at Main (Non-Residential)	Custom	-
11	Damage Meter Charge	380	-

Note:
(1) Charge varies depending on request.

4.1. Lawyer Letter Handling Charge

104. The lawyer letter handling charge was intended to be applied to customers in the EGD rate zone when their lawyer's office requested historical information related to their gas bill. In practice, Enbridge Gas does not charge for these requests in the EGD rate zone and there is no comparable charge in the Union rate zone.

105. Enbridge Gas is proposing to eliminate this charge as the charge is not used. Customers have access to self-serve options to retrieve historical information and customers who are not able to access self-serve options will receive historical information free of charge.

4.2. Request for Service Call Information

106. The request for service call information charge was intended to be applied to customers in the EGD rate zone who requested a summary of their service call results. In practice, Enbridge Gas does not charge for these requests in the EGD rate zone and there is no comparable charge in the Union rate zone.

107. Enbridge Gas is proposing to eliminate the request for service call information charge as the charge is not used. Customers will continue to be able to request a summary of their service call results free of charge.

4.3. Duplicate Bills

108. The duplicate bills charge was intended to be applied to customers in the Union rate zones when they requested a duplicate copy of their bill. In practice, Enbridge Gas does not charge for these requests in the Union rate zone and does not have a comparable charge in the EGD rate zone.

109. Enbridge Gas is proposing to eliminate the duplicate bills charge as the charge is not used. Customers have access to self-serve options to retrieve their bills and customers who are not able to access self-serve options will receive a copy of their bill free of charge.

4.4. Detailed Billing Analysis/Statement of Account

110. The detailed billing analysis/statement of account charges were intended to be applied to customers in the Union rate zones when they requested a detailed analysis of their account. In practice, Enbridge Gas does not charge for these requests in the Union rate zone and does not have a comparable charge in the EGD rate zone.

111. Enbridge Gas is proposing to eliminate this charge as the charge is not used. Customers have access to self-serve options to retrieve their historical information and customers who are not able to access self-serve options, or who have questions about the information available, will receive their account information and support free of charge.

4.5. Valve Lock Charge – Field Investigator/Construction & Maintenance

112. The valve lock occurs when the service is shut off from the street by closing the valve.

113. Enbridge Gas currently charges $135 for the field investigator and $280 for construction & maintenance for the valve lock service in the EGD rate zone and does not charge for this service in the Union rate zones.

114. Enbridge Gas is proposing to eliminate this service charge as the valve lock service is rarely a customer requested service and the amounts collected from this service charge are immaterial.

4.6. Removal of Meter

115. Removal of meter occurs when the physical meter is removed from the premise. Enbridge Gas charges a service fee of $280 for the removal of meter in the EGD rate zone and does not charge for the service in Union rate zones.

116. Enbridge Gas is proposing to eliminate this service charge as the service is rarely used and the amounts collected from this service are immaterial.

4.7. Meter Lock

117. The meter lock service is the action of turning the meter off so that gas is not flowing at the premise.

118. Enbridge Gas is proposing to remove reference to the meter lock charge, as under the Gas Distribution Access Rule (GDAR), utilities are not to apply any charges when disconnecting a customer for non-payment. In compliance with GDAR, Enbridge Gas currently does not charge for meter lock for non-payment in both the EGD and Union rate zones.

4.8. Meter in/out

119. The meter in/out charge is intended to recover costs of relocating the meter from the inside to the outside of the customer premise per customer request.

120. Enbridge Gas charges a service fee of $280 for the meter in/out in the EGD rate zone and does not charge for the service in the Union rate zones.

121. Enbridge Gas is proposing to eliminate this service charge as the service is rarely used and the amounts collected from this service are immaterial.

4.9. Cut Off at Main

122. The cut off at main service occurs when a customer requests that their service line be cut off at the main line for safety purposes. Generally, this service is provided when a customer is completing a demolition or renovation or switching to another energy source.

123. Enbridge Gas's cut off at main charge is $1,300 for residential customers or a custom charge amount based on the cost to provide the service for certain residential and non-residential in the EGD rate zone. Enbridge Gas does not charge for the service in Union rate zones.

124. Enbridge Gas is proposing to no longer charge for this service to promote operational safety and maintain safety standards of the Enbridge Gas distribution system. Having a prohibitive charge for this service can deter customers from requesting the service leading to abandoned natural gas lines and meters, which poses a safety and operational risk.

125. Enbridge Gas also asked respondents for feedback on the cut off at main charge as part of the customer engagement. The question asked whether the homeowner should be charged based on the full cost to provide the service, charged based on a partial cost to provide the service, or receive no charge for the service. The responses were mixed, with no strong preference for any scenario presented. The responses were 33% of respondents supporting not charging for cut off at main and 30% of respondents supporting fully charging for the service. The remaining respondents supported a partial charge, did not have an opinion, or didn't know. Further details can be found in the customer engagement report provided at Exhibit 1, Tab 6, Schedule 1, Attachment 1, pages 263-264.

126. For these reasons, Enbridge Gas is proposing to adopt the approach used in the Union rate zones and no longer charge for the service.

4.10. Damaged Meter

127. The damaged meter charge is intended to recover costs for damage of a meter at a customer premise.

128. Enbridge Gas charges a service fee of $380 for the damaged meter in the EGD rate zone and does not charge for the service in the Union rate zones.

129. Enbridge Gas is proposing to eliminate this service charge as the service is rarely used and the amounts collected from this service are immaterial.

TAB 3

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit 4, Tab 4, Schedule 2, p. 33

Question(s):

At the above reference, it is stated when discussing Operations costs increases for the 2022 Estimate versus 2021 Actuals that:

> Further pressure on the cost of locates is driven by the introduction of Bill 93 which was passed into law on April 14, 2022. The new regulations mandate absolute liability compliance for 5 day and 10 day locate deliveries depending on the scope of the excavation project.

Please provide Enbridge Gas's forecasts of the cost impacts of Bill 93 for the 2023 to 2024 period.

Response:

Enbridge Gas has included a conservative amount in the 2023 and 2024 forecast for locate cost increases. The forecast takes into account inflation, cost pressures from various sources, and early estimates from 2022 of the impacts related to Bill 93. The locate forecast for external locate costs was determined based on historical locate request volumes and the average cost of delivering a locate plus inflationary increases. Internal locate costs were determined by the full time equivalent (FTE) resources required to manage and support the execution of the locate delivery process including year-over-year wage increases. Please see Table 1 for locate cost forecast for the 2023 Bridge Year and 2024 Test Year[1] relative to 2022. A portion of the anticipated cost increase expected is included in this forecast with a significant level of cost uncertainty related to Bill 93 still remaining.

[1] Enbridge Gas filed a correction to the 2024 locate costs described at Exhibit 4, Tab 4, Schedule 2 and Exhibit 9, Tab 1, Schedule 3 on March 8, 2023. The 2024 locate costs had previously been stated as $51.1 million, including $45 million for operating and maintenance costs for external services and $6.1 million for internal company resources that provide administrative support.

Table 1
Locate Cost Forecasts

Line No.	Particulars ($ millions)	2022 Actuals	2023 Bridge Year	2024 Test Year (1)
		(a)	(b)	(c)
1	External Costs	39.9	48.2	51.1
2	Internal Costs	6.5	7.1	7.5
3	Total	46.4	55.3	58.6
4	Change from Prior Year	-	8.9	3.3

Note:
(1) Exhibit 4, Tab 4, Schedule 2, paragraph 85 and Exhibit 9, Tab 1, Schedule 3, paragraph 23, updated March 8, 2023.

Given the cost uncertainty, Enbridge Gas is proposing a new Locate Delivery Service Variance Account (LDSVA) to record the variance between the external locate costs of $51.1 million and the actual external costs for locate delivery services. This will include the costs for Enbridge Gas to deliver locate services, but also the costs incurred by Enbridge Gas to request a locate for the provision of its own services, as it is expected that other third parties will also initiate a fee for locate services. Enbridge Gas has also proposed to record the revenue collected (net of bad debt costs) from the proposed service charge in the LDSVA as an offset to the increased costs.

Enbridge Gas forecasts that the cost impacts of Bill 93 for the 2023 to 2024 period includes but is not limited to onboarding additional locate resources with robust training, office resources for new reporting requirements by Ontario One Call, increased quality assurance activities and contractor management and oversight. Prior to 2023 there were no actual cost impacts from Bill 93 as the regulations do not come into effect until April 1, 2023.

Enbridge Gas expects external costs for locate services to materially increase from the forecast in response to increased locate delivery compliance requirements as a result of Bill 93 legislation. These costs are currently expected to increase by $20 million to $45 million but may vary based on evolving industry factors as well as any third-party charges that may be incurred should others choose to charge for locates as well. These new cost pressures as a direct result of Bill 93 compliance requirements are difficult to definitively quantify as they are subject to multiple external factors with high levels of variability. Dramatically increased efforts to compete, market, attract, and retain new quality locator resources despite Ontario’s current labour challenges are a critical requirement of Enbridge Gas and its service providers as result of Bill 93 legislation.

Enbridge Gas forecasts an annual incremental cost impact primarily as a result of Enbridge Gas service providers onboarding and retaining 500 or more new contractor locators at a fully loaded annual rate in the approximate range of $50,000 to $80,000 per locator. Internal FTEs will be onboarded as necessary for the management and oversight of contractors to ensure the safety and compliance of contractor service deliveries. This number is not yet known.

In response to anticipated cost increases, Enbridge Gas's proposed new locate delivery service charge is intended to cover the costs associated with delivering locates to third party contractors. While there may be bad debt associated with collecting the new service charge, the charge is intended to protect Enbridge Gas customers from subsidizing the cost of locates associated with other utilities' and municipalities' excavation projects. The proposed service charge will not be applied to Enbridge Gas customers requiring locates for their private property.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. 9/T1/S3/p. 9

Question(s):

EGI is proposing to establish the Locate Delivery Services Variance Account in response to Bill 93, the Getting Ontario Connected Act, which was recently passed.

a) Does EGI intend to record the revenue received from the proposed service charge in that account?

b) How did EGI determine its forecast of external locate delivery costs of $45 million which is included in base rates?

c) How was the $6.1 million derived?

d) Where are these costs set out in the O&M schedules?

e) Why does EGI expect that the external costs for locate services to materially increase from the forecast?

Response:

a) Yes, the revenue is proposed to be recovered in the Locate Delivery Service Variance Account.

b-e) Please see response at Exhibit I.4.4-STAFF-122.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (OGVG)

Interrogatory

Reference:

Exhibit 9 Tab 1 Schedule 3 Page 10

Question(s):

Enbridge Gas proposes that the LDSVA record the variance between the actual external costs for locate delivery services, and the external locate delivery costs included in base rates of $45 million. External locate delivery costs includes both the external costs to provide locate delivery services and receive locate delivery services for Enbridge Gas's own operations. The cost variance in the LDSVA will be offset by the revenue collected through the new locate delivery service charge applicable to third-party contractors and other utilities who request locate services from Enbridge Gas.

a) Please explain any objections that EGI may have with a proposal that would escalate the proposed $45 million annual threshold in accordance with any escalator applied to EGI's rates during any approved IRM term before EGI's next rebasing application?

Response:

a) Enbridge Gas would not object to a proposal that would escalate the proposed $51 million annual threshold (updated March 8, 2023) in accordance with any price cap escalator applied to Enbridge Gas's rates during the IRM term.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

9-1-3, p.8-11

Question(s):

With respect to the proposed Locate Delivery Services Variance Account:

a) Please explain how the $45M locate cost budget that included base rates was determined.

b) Is Enbridge forecasting any revenue through the proposed new locate delivery service charge as part of Other Revenue? If so, how much?

Response:

a) Please see response at Exhibit I.4.4-STAFF-122.

b) No, Enbridge Gas has not forecasted any revenue for the proposed new locate delivery service charge as part of Other Revenue. Collected revenue related to this charge will be recorded in the proposed Locate Delivery Services Variance Account effective January 1, 2024. Please see Exhibit 9, Tab 1, Schedule 3, updated March 8, 2023.

TAB 4

ONTARIO ENERGY BOARD

FILE NO.: **EB-2022-0200** **Enbridge Gas Inc.**

VOLUME: **Technical Conference**

DATE: **March 24, 2023**

MR. STEVENS: Sorry, just to finish my thoughts, as you know, there is no proposal by Enbridge in the context of this application for AMI.

MR. JARVIS: Understood. And I apologize for not expressing that interest. It is a very strong interest in the commercial sector which is using gas meter data and gas interval data extensively for diagnostics and for helping them move down the net zero path, so, yes, I -- we will consider dropping you a note, David, about what we might like to inquire of panel 5, if that makes sense.

MR. STEVENS: Thank you.

MR. JARVIS: And that's my questions.

EXAMINATION BY MR. MILLAR:

MR. MILLAR: Thank you, Mr. Jarvis. We're really rolling now, and last and perhaps least, the OEB Staff.

I'm going to introduce myself as the questioner.

Good afternoon, panel. I hope to be quite quick on this. I just have a couple of questions about your proposed new locates charge. And just to frame the issue, it might be helpful to pull up Exhibit 8, tab 3, Schedule 1, page 13. As that's coming up, I can probably start with the question. There we go. Thank you.

If we could go to page 13 of tab 3, Schedule 1. You could scroll down to the bottom of that page, please. Thank you very much.

Okay. So just to frame this, as part of the application Enbridge is proposing to create -- it's a new charge for locates; is that correct?

MR. McGIVERY: Michael McGivery. That's correct.

MR. MILLAR: Okay. And the charge is proposed to be $200, but it is only going to be for third-party contractors and utilities; in other words, your existing customers won't have to pay a charge; is that correct?

MR. McGIVERY: That's correct.

MR. MILLAR: And currently, before this charge comes into place, assuming it does, there is no specific charge for locates; is that right?

MR. McGIVERY: Currently there is no specific charge for locates.

MR. MILLAR: Okay, but the costs for that are all -- they are kind of worked into your existing O&M budget; is that right? It's not that Enbridge is doing this as charity work; it is just that it is included in distribution rates through O&M, I assume?

MR. McGIVERY: That's correct.

MR. MILLAR: So the costs are currently being recovered from rate-payers, just not part of a discrete charge?

MR. McGIVERY: That's correct.

MR. MILLAR: And you are seeking approval for this new charge so that you can recover at least some of those costs directly through this charge; is that right?

MR. McGIVERY: I'd like to clarify that.

We are seeking this charge to recover the incremental costs above and beyond what we propose in rates.

MR. MILLAR: Okay, so there will still be -- some of it will be recovered through your O&M budget, but you are predicting certain incremental costs, and I think you talk about that.

You'll see paragraph 45 in front of you and 46.

This relates to, I think it's the Getting Ontario Connected Act; you are familiar with that?

MR. McGIVERY: Yes, I am.

MR. MILLAR: And you are predicting that that will lead to some incremental costs with respect to locates?

MR. McGIVERY: That's correct.

MR. MILLAR: And you are proposing to recover those costs through this new charge?

MR. McGIVERY: That's correct.

MR. MILLAR: Okay. And do you have a sense -- one of the -- you have some bullet items, if we just scroll down a little bit in paragraph 46, there -- there you go. You see (b), you expect a number of locates requests will increase.

I'm sorry if there is some background noise here. There is construction at my neighbour's, so I'll try and speak loudly and clearly.

With respect to these new requests, do you have a sense as to who those are going to likely to come from? And I guess, to put it more specifically, do you expect these are going to be related to broadband work from the telecoms, or is it broader than that, or what can you tell me about that?

MR. McGIVERY: It is hard to quantify with contracts, just due to the recent legislation, the regulations being published as of February, which take effect April 1st, but we believe there will be materiality and significant locate requests coming from all sectors of the industry.

MR. MILLAR: And, sorry, which industry?

MR. McGIVERY: All industries.

So the legislation now mandates that anyone who is known to be digging without a locate can receive a monetary penalty, which wasn't -- which does not exist previously.

MR. MILLAR: Okay, so these could be from -- to be clear, these could be from telecoms, they could be from other utilities, they could be from any number of folks?

MR. McGIVERY: That's correct, municipalities, builders, telecoms.

MR. MILLAR: And you don't have a particular breakdown as to who you are most likely to get these requests from?

MR. McGIVERY: No, that would be very difficult to quantify at this time, as this would be 2023, 2024 will become the base year for this new legislation.

MR. MILLAR: Right. Thank you. We circulated in advance, and I believe Ms. Montfortin has it ready, a news release that OEB Staff happened upon with respect to the new locates charge.

Could I ask to have that pulled up, please? There we go.

Okay. And there is not much to this. It is really just to frame the question.

I see if you scroll down a little ways you will see "what is changing?" and it says there effective May 1st

Enbridge intends to start imposing this new charge.

My observation would be that, barring a miracle or I guess a time machine, you are not likely to have final approval through this proceeding for a discharge or any other by May 1st.

So I'm wondering if you can help me here.

Is this charge you intend to propose before this proceeding ends?

MR. McGIVERY: That communication went out, as you can see on the screen. Since then we've sent out an additional communication letting industry know that this charge is on pause.

However, the spirit of the communication as we continue to consult with industry on this charge is to look and treat the locate, the incremental locate delivery, due to Bill 93, very similar as our damage cost recovery due to requested work on behalf of other utilities, similarly, as we recoup already in our current rate case per our structure and framework to protect the rate-payers.

MR. MILLAR: Okay, understood.

But just to follow-up on my question: Am I correct that you are not -- and David, if you want to chime in, that's fine as well, but am I correct that you are not proposing to actually charge the fee until you have OEB approval?

MR. McGIVERY: I cannot --

MR. STEVENS: I can speak to that briefly, and I'm sure Mike will have something to add.

That may turn out to be the case, Michael.

Enbridge took the view that it is appropriate to let people know about this charge and to -- and to ask for approval here.

It's not entirely clear that approval is needed to make a charge to non-customers, which is what's happening here.

This is a charge to third parties and, as Michael indicated, these aren't charges to Enbridge's customers.

That being said, I think it's probably academic, as Enbridge has determined that it's going to suspend the charge of this amount, and that won't be starting on May 1st, 2023.

MR. MILLAR: David, could I ask for the company's position on whether or not OEB approval is required for this charge? And if you need to think about that and come back, that's fine.

I just -- I'd like to understand if this is a request under section 36 of the Act or if it is not?

MR. STEVENS: I think it's probably best to come back in writing.

I -- certainly from Enbridge's perspective it is important to have things in writing [audio dropout] took place, and that, I think, lies behind some of this request, but we'll confirm in writing Enbridge's position on approval of the charge.

MR. MILLAR: Okay, thank you. I'll mark that as JT3.38.

UNDERTAKING NO. JT3.38: TO CONFIRM IN WRITING ENBRIDGE'S POSITION ON APPROVAL OF THE CHARGE.

MR. MILLAR: And David, to the extent that you can, I'm hoping the answer is more than -- well, it's either yes or if it's no just some explanation as to why it's not covered under section 36.

And again, I'm not seeking to disagree here. I just think it would assist Staff so we don't have to return to this cross-examination to understand if it's not part of section 36. If you don't need approval, why not.

MR. STEVENS: Understood.

MR. MILLAR: Okay. And I -- I'm sorry, I should have marked as an exhibit, I don't think it is actually on the record, this news release, so I propose to mark that as KT3.4.

EXHIBIT NO. KT3.4: NEWS RELEASE.

MR. MILLAR: And witnesses, I'm sorry, Mr. Parkes, I believe, has one follow-up question.

That conclude me, and you'll be happy to hear after Mr. Parkes we're done, so I'll pass it to you, Mr. Parkes.

EXAMINATION BY MR. PARKES:

MR. PARKES: Thanks very much, Mr. Millar. The last question of the day, big honour.

I had a question on the IRP deferral accounts.

If we could turn to I9.1, Staff 248. Thank you.

So Enbridge has proposed to keep the IRP operating costs and capital costs deferral accounts with the definitions that were approved in the IRP proceeding

TAB 5

ONTARIO ENERGY BOARD

FILE NO.: **EB-2022-0200** **Enbridge Gas Inc.**

VOLUME: **Technical Conference**

DATE: **March 30, 2023**

MS. SCOTT: Okay, I'll leave it there then, thank you.

The next one, which you don't need to pull up, is SEC-175 because it again refers to Staff-122.

This is related to this issue of the increase in the locates costs and Bill 93. So if you could just move to -- there is a table on the next page.

So external cost and internal cost. I'm just trying to make sure I understand this. So this is the cost for Enbridge to do locates for other utilities who request them. And does this also include the cost of other utilities if they charge doing locates for Enbridge?

MS. BURNHAM: Jennifer Burnham. Yes, that is correct. These would be the costs for us to provide locates to other municipalities, utilities, contractors, the general public who request locates. As well, if we have internal costs for those locates, or have to pay for locates which I don't -- I'd have to check right now. I don't believe we paid for locates anywhere, these would be the costs incorporated into that.

MS. SCOTT: That was my next question, is do you pay -- is anybody currently charging for locates and your understanding --

MS. BURNHAM: Subject to check I don't believe we are paying for locates in Ontario right now.

MS. SCOTT: So as I understand it for 2024 built in -- based on Bill 93 the costs are going to go up because you have to respond quicker, sort of, in a nutshell; is that correct?

MS. BURNHAM: Whole cost drivers right now, so one is the costs of our contractors are increasing so that would be in the external cost bucket and part that's driven by, you know, staffing challenges they have had, attracting talent, hiring and training, but then also the increased number staff that they have to have to deliver to the new compliance measures that are coming out as part of Bill 93.

MS. SCOTT: And you are proposing introducing a $200 fee for locates; is that correct?

MS. BURNHAM: Yes, that is a proposal that is currently on the table.

MS. SCOTT: And that will cover both external and internal costs for the particular -- for the locates?

MS. BURNHAM: It would -- I believe it's the -- yes, it's the cost for us to deliver those locates. It's what it is planned to cost.

A portion, and it is on the best efforts of what we understand today. Obviously there is a lot of unknowns related to the impact of Bill 93, but that was the recommended amount to start with, to determine what we believe we know today is the cost of the locates -- to deliver those locates.

MS. SCOTT: So I guess I'm -- it seems to me there's built in budget in the revenue requirement, and you're also asking for this new charge, and I'm not sure how those two interact. So maybe you can explain that.

MR. HEALEY: Colin Healey. Just to add to that, the time of when this information was put together, it was still in infancy or early days of understanding the impact of Bill 93. So there is minimal base rate there in to these numbers as a result of Bill 93, purely as a result of the timing of when the rate base was filed.

MS. SCOTT: Yes. And I was going to actually ask you that, because my understanding is that you've had almost a year now of experience with Bill 93, have you?

MS. BURNHAM: Jen Burnham. I believe it is just coming into effect starting in April and they're still working things out.

MS. SCOTT: Oh, it's this year that it's -- okay.

MS. BURNHAM: Yes. There was a notice today. April 1st is when the compliance measures start, this year.

MS. SCOTT: Oh, okay. So the bill was enacted a year ago; it's just kind of coming into effect now. Okay, so you don't have any experience. Okay, so that -- so you are saying a minimum amount built into rates and you've chosen the figure of -- the idea of $200, not really knowing if that's going to cover your costs. Would that be correct?

MS. BURNHAM: Yes. I would say -- I mean, what we have in this table here are the costs to deliver the locates for what we experience and the increased costs that we've seen over time. The $200 charge is our estimate right now. I think that's why there were some treatment recommendations on how we treat that. I know this panel -- it was spoken about in another panel -- I think panel 11 -- a bit, but, yes, this is what we have proposed right now.

MR. KITCHEN: Ms. Scott, it is Mark Kitchen of

Enbridge. Just to -- I think this might be a bit helpful, too, is that the locate charge will only be charged to third-party contractors. It will not be charged to Enbridge Gas customers.

MS. SCOTT: Oh, that is helpful, yes. I was under the understanding that everybody was paying for it. Okay, thank you. I appreciate that. And I will -- look, I'm sorry if it was discussed under another panel. I haven't been listening to all of the days, so I will go back to panel 11 and look at that, too. So thank you.

SEC-176 is the next one, and this is where we asked about the as-a-service model.

MR. HOU: Ms. Scott, Edward Hou. Yes, the description of the as-a-service model. Is that correct? I just want to clarify the question?

MS. SCOTT: Well, I haven't asked it yet.

MR. HOU: Sorry, yes.

MS. SCOTT: Yes. So as I understand it, I guess -- well, there are two parts to what I would like to ask. One is about -- I think we originally asked if there was a business case for this and we were told, no, that there wasn't one. And I was just trying to get a better idea. Part of SEC-176 says that, since that time, as technology solutions reached end of life, the only option is as a service, as traditional on-premise solutions are not readily available or cost effective.

And I guess I will ask again: Was there no analysis done to show that they were no longer cost effective?

TAB 6

ENBRIDGE
Distribution Protection
Damage Prevention
News

Summary

On April 14, 2022, the Getting Ontario Connected Act was passed into law, and resulted in major changes to the Ontario Underground Infrastructure Notification System Act which governs how underground facilities are located in Ontario. The legislative changes aim to remove barriers to timely locate delivery, improve and streamline compliance, and enhance Ontario One Call's powers.

Historically, Enbridge Gas has completed gas facility locates at no direct charge to locate requestors. As a result of these legislative changes, Enbridge Gas has made significant investments in associated operational improvements.

To ensure that our gas distribution service customers are protected from incurring the costs of services rendered to other parties, Enbridge Gas will be implementing a new locate delivery charge. This charge will be applied directly to third-party contractors and other utilities who make these locate request.

What is Changing?

Effective May 1, 2023, Enbridge Gas (including its Ontario based affiliates), will begin to directly charge third-party contractors and other utilities for their utility locates. Enbridge Gas will apply a charge of $200 CAD (plus applicable taxes) per locate request where a field locate (paperwork and ground markings) is completed by Enbridge Gas.

Locates requested by property owners for a property where they or their tenant reside, will not be subject to this charge.

Questions?

Please see the Charging for Locates FAQ for more details.

Please email locate.charges@enbridge.com if you have any additional questions.

Regards,
Enbridge Gas

Frequently Asked Questions

1. **Under what circumstances will requestors be charged for locates?**
   Enbridge Gas will charge third-party contractors and other utilities for each utility locate request that Enbridge Gas responds to where a field locate (paperwork and ground markings) is completed. Locates requested by property owners, for a property where they or their tenant reside, will not be subject to a direct charge. However third-party contractors and other utilities who request a locate for work at a property on behalf of the property owner or their tenant, will be subject to this charge upon completion of the locate paperwork and ground markings.
   Third-party contractors and other utilities using a third-party dedicated locator approved to locate Enbridge Gas assets (including those of its Ontario based affiliates) will be charged by the dedicated locator and not Enbridge Gas.

2. **What happens if I receive a clearance for Enbridge Gas on my locate request?**
   Enbridge Gas does not charge for locate requests where there are no Enbridge Gas assets in the locate area and a clearance is issued.
   Excavators should request locates for as precise an area as possible relative to their work plan to increase the potential that a clearance can be issued.

3. **Will I be charged for remarks and relocates?**
   Enbridge Gas will charge for remark/relocate requests where a field locate (paperwork and ground markings) is completed.
   Excavators should plan their work start date based on the timelines of their locate request to reduce the potential that their locates will expire before they start work.
   Excavators should follow all third-party requirements associated with preserving and maintaining locate markings to reduce the potential that the locates will require remarks.

4. **Are homeowners or tenants charged for locates?**
   Locates requested by a property owner, for a property where they or a tenant reside, will not be subject to a direct charge, however third-party excavation contractors and other utilities will be subject to a charge.

5. **Can a homeowner undertaking work on their property request a locate for their contractor to avoid incurring charges?**
   No. It is the responsibility of the excavator undertaking the ground disturbance to request the locates.

6. **What forms of payment are accepted?**
   Enbridge Gas accepts credit card payments (through an individual link generated

when the charge is issued) or payments by cheque made payable to Enbridge Gas, Accounts Payable.
Enbridge Gas does not accept cash payments.

7. **Can I add the charge to my gas bill?**
   We are not offering the ability to add locate delivery charges onto our natural gas bills.

8. **I am a customer of Enbridge Gas, does that mean I still need to pay for a locate?**
   Enbridge Gas customers that request locates for work on their own property where they or their tenant reside, will not be charged. Enbridge Gas customers who operate as excavators or are requesting locates for work outside of their own residential property will be subject to the locate charge.

9. **Who do I contact for disputes about my locate charge?**
   For any disputes related to your Enbridge Gas locate charge you can email locate.charges@enbridge.com.

10. **When are my locate charge payments due?**
    Invoices for locate charges will be issued on a monthly basis with payment required within 45 calendar days from the invoice date.

11. **Do I still need to pay for the locate if it wasn't delivered within five (5) business days?**
    Yes. Upon placing your locate request through Ontario One Call for which Enbridge Gas is required to locate its underground assets, you will be charged whenever a field locate (paperwork and ground markings) is completed.
    Enbridge Gas makes every practicable effort to respond to locate requests within five (5) business days. The charge is required to cover the cost of our locate services.
    To support timely completion of locate request responses, Enbridge Gas suggests that excavators:
    - Request locates for as precise of an area as possible relative to their work plan to increase the potential that a clearance can be issued and/or a field completion can be issued as fast as possible.
    - Only place locate requests for work that they reasonably plan to start in the near future so as to prevent excess / unnecessary requests and reduce the potential that their locates will expire before starting work.

12. **What alternatives do I have to paying Enbridge Gas for locating its assets?**
    It is a legal requirement in Ontario that prior to any ground disturbance, the excavator must obtain a valid locate response from all affected infrastructure owners impacted by the ground disturbance activities.

As an alternative, a project owner can apply with Ontario One Call to use a dedicated locator authorized to locate the assets of the infrastructure owner in accordance with regulations. The cost of a dedicated locator will be borne by the project owner in accordance with the Ontario One Call legislation.

13. **Why is Enbridge Gas making the decision to charge for locates?**
The cost to deliver locates has increased significantly, and we are proactively working to recover costs for providing locate services directly from third-party contractors and other utilities who make these locate requests.

14. **What are you going to do with the money that you receive for locates?**
We are collecting money for line locates to offset our own costs. Enbridge Gas does not earn a profit on the money received for locates.

15. **What is the cost of the locates?**
$200.00 CAD (plus applicable taxes) per completed field locate (ground markings and paperwork) will be charged.

16. **How did you arrive at a $200 fee – how can I be assured this is reasonable?**
Enbridge Gas completed a detailed analysis of the costs associated with completing a standard locate, including field locate delivery, locate delivery administration and field locate safety controls.

17. **Now that you are charging for locates, will you commit to a five-day turnaround?**
Enbridge Gas makes every practicable effort to respond to locate requests within five (5) business days.
To support timely completion of locate request responses, Enbridge Gas suggests that excavators:
    - Request locates for as precise of an area as possible relative to their work plan to increase the potential that a clearance can be issued and/or a field completion can be issued as fast as possible.
    - Excavators should plan their work start date based on the timelines of their locate request to reduce the potential that their locates will expire before they start work.

18. **Why are you charging professional excavators and not residential property owners – is this fair?**
With the changes in the legislation, Enbridge Gas is now looking to allocate the costs of delivering locates directly to third-party excavation contractors and other utilities who make these locate request.

19. **Have you assessed the risk that this additional cost will dissuade contractors from obtaining locates?**
    Yes. Regardless of whether or not there is a charge for obtaining locates, it is a legal requirement under the Ontario Underground Infrastructure Notification System Act that all parties obtain a valid locate prior to conducting any ground disturbance activities in Ontario.

    Any excavator that commences ground disturbance activities without a valid locate may be subject to a $10,000 penalty. Any excavator that continues ground disturbance activities past the expiry date of a valid locate may be subject to a $8,000 penalty.

20. **How can I learn more about the Getting Connected Ontario Act?**
    Information on the Getting Connected Ontario Act is available online:
    - Ontario Underground Infrastructure Notification System Act, 2012, S.O. 2012, c. 4
    - Dedicated Locator – Ontario One Call

TAB 7

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 212

To confirm in writing Enbridge's position on approval of the charge.

Response:

The OEB has broad authority to establish and approve charges from regulated utilities, and that authority has been exercised to approve charges to customers (account service charges, for example) and to non-customers (labour charges applicable to address damages by any party to the Company's facilities). Enbridge Gas's view, however, is that it is permissive rather than mandatory for the OEB to review and approve charges applicable to non-customers.

In this case, if Enbridge Gas's proposed locate delivery service charge were to be applicable to Enbridge Gas's own customers, then this would be something that would have to be approved by the OEB and included in Rider G. However, Enbridge Gas does not believe that OEB approval is required where these charges are levied to third-party contractors and other utilities (non-customers).

Two important points of context should be added.

First, even though Enbridge Gas is not required to obtain OEB approval for a locate delivery service charge to non-customers, the review and approval of the charge is helpful from Enbridge Gas's perspective. The revenue from the locate delivery service charge is intended to offset the additional costs to be incurred by Enbridge Gas that are not included in rates. It is in the joint interest of Enbridge Gas and ratepayers that such costs are indeed recovered, and that they are recovered from the parties causing the costs to be incurred (non-ratepayers). OEB approval of the locates charge will assist Enbridge Gas in maximizing the recoverability of its costs. Being able to tell third-party contractors and other utilities that the charge is reviewed and approved by the utility's regulator increases the likelihood that third parties will pay when invoiced. Additionally, where Enbridge Gas's invoices/charges are challenged in a legal proceeding (likely Small Claims Court), OEB approval of the charges is a helpful fact in support of recovery.

Second, as noted during the Technical Conference (TC Tr. Vol 3. 209-212), Enbridge Gas has suspended the charging of the new locate delivery service charge that was planned for May 1, 2023. As such, it may be the case that the charge will not actually be implemented before January 1, 2024, by which time the requested approval in this Application will have been determined. Please see Attachment 1 for a copy of the communication issued by Enbridge Gas on March 23, 2023 confirming that the Company will not be starting to levy the new locates charge on May 1, 2023.

On day 7 of the Technical Conference (TC Tr Vol 7, 95), the Company gave a response, subject to check, to whether any parties are currently charging Enbridge Gas for locates. There are a few municipalities that are charging for locates in Ontario. These are very few compared to the number of locates provided.

ENBRIDGE

Distribution Protection

Damage Prevention

Update

Enbridge Gas would like to provide notice of our decision to put the implementation of the locate delivery charge on pause. We will use this time to continue our industry consultations and Enbridge will provide additional information once we have confirmed our approach.

Enbridge remains committed to the safe and timely delivery of locates.

For any additional inquiries please contact us at locate.charges@enbridge.com

Regards,

Enbridge Gas

TAB 8

PARTIAL SETTLEMENT PROPOSAL

Enbridge Gas Inc. Application for approval of 2024 Rates

June 28, 2023

	Description	Page
	appropriate?	
27.	Is the proposed rate implementation and mitigation plan for 2024 rates appropriate?	49
28.	Are the proposed changes to the terms and conditions applicable on January 1, 2024, to existing rate classes appropriate?	50
29.	Are the proposed miscellaneous service charges, including Rider G and Rider M, appropriate?	51
30.	Are the proposed Direct Purchase Administration Charge (DPAC) and Distributor Consolidated Billing (DCB) charges appropriate?	52
31.	Is the proposal for harmonization of certain existing deferral and variance accounts appropriate?	53
32.	Is the proposal to close and continue certain deferral and variance accounts and establish new ones appropriate?	55
33.	Is the proposal to dispose of the forecast balances in certain deferral and variance accounts appropriate?	57
34.	Is the proposed regulatory treatment of the Natural Gas Vehicle Program appropriate?	58
35.	Is the proposed regulatory treatment of the Distributor Consolidated Billing Program appropriate?	59
36.	Is the proposal for the extension of the existing financial terms of the Open Billing Access Program for ten months until October 31, 2024 appropriate?	59
37.	Is it appropriate to have an earnings sharing mechanism for 2024?	60
38.	How should Dawn Parkway capacity turnback risk be dealt with?	60
39.	Is the proposed harmonized methodology for determining the amount of storage space and deliverability required to serve in franchise customers appropriate, and is the proposed allocation of storage space and deliverability among customers appropriate?	60
40.	Should the OEB grant Enbridge Gas's request for a partial exemption for 2024 from the Call Answering Service Level, Time to Reschedule a Missed Appointment and Meter Reading Performance Measurement targets set out in GDAR?	61
41.	How should the OEB implement the approved 2024 rates relevant to this proceeding if they cannot be implemented on or before January 1, 2024?	61

Parkway to Dawn toll to reflect that customers now deliver primarily to Dawn.

Supporting Parties: APPrO, BOMA, CME, CCC, EP, ED, FRPO, GEC, IGUA, Kitchener, LPMA, OGVG, OPI, PP, QMA, SEC, SNNG, VECC.

Evidence: The evidence in relation to this issue includes, but is not limited to, the following:

8.4.1	Service Harmonization
8.4.1.1	Service Harmonization Mapping
8.4.2	Distribution
8.4.3	Bundled Service
8.4.4	Semi-Unbundled Service
8.4.5	Unbundled Service
8.4.6	Ex-franchise Services
8.4.7	Interruptible Service Study
8.4.7.1	Interruptible Rates Study – Rate Comparison
8.5.1	Terms & Conditions of Service Harmonization
8.5.1.1	Terms & Conditions of Service Harmonization – Conditions of Service
8.5.1.2	Terms & Conditions of Service Harmonization – Contract Comparison
8.5.1.3	Terms & Conditions of Service Harmonization – Summary of Changes to Ex-franchise GT & Cs – Combined
8.5.1.4	Terms & Conditions of Service Harmonization – Summary of Changes to Ex franchise GT & Cs – Harmonized
8.5.1.5	Terms & Conditions of Service Harmonization – Ex franchise combined GT & Cs
8.5.1.6	Terms & Conditions of Service Harmonization – Ex franchise harmonized GT & Cs
Exhibit I.8.4	Exhibit 8, Tab 4 Interrogatories
Exhibit I.8.5	Exhibit 8, Tab 5 Interrogatories
8 TC Tr. 23 - 117	Technical Conference Panel 10
JT8.4 - JT8.16	Panel 10 Undertakings

29. Are the proposed miscellaneous service charges, including Rider G and Rider M, appropriate?

Partial Settlement

Subject to the following qualifications and changes, Parties accept that the proposed miscellaneous service charges as filed by Enbridge Gas are appropriate:

- Meter dispute test charge – Parties have agreed that the common Enbridge Gas charge for meter dispute requests should be $100 (halfway between the current charges in the EGD and Union rate zones).

- Late Payment Penalty charge – For the purposes of settlement, Parties accept the proposal to continue a late payment charge of 1.5% per month (19.56% per annum). Not all Parties agree that the late payment fee of 19.56% per annum is cost based or a reasonable charge. However, all Parties agree that the fee was established on a generic basis by the OEB and if reviewed should be reviewed on a generic basis which would include electricity distribution utilities.

- Extra length charge – There is no settlement on the appropriate charges for individual customer connections, including charges for individual service lines and meters.

As advised in Enbridge Gas's letter dated May 24, 2023, Enbridge Gas is requesting a Locate Delivery Services Variance Account on a generic basis along with numerous large distributors (gas and electric). In its May 24, 2023 letter, Enbridge Gas indicated that if the requested generic deferral account is not approved and/or circumstances change such that an approved service fee for locates requests becomes necessary for Enbridge Gas, then the Company may choose to pursue that request at a later date. In a letter dated June 14, 2023, the OEB requested more information from the requesting utilities (including Enbridge Gas) before making a determination about whether to approve the requested generic account. Enbridge Gas reserves the right, therefore, to seek approval of a locate delivery charge as part of Phase 2.

Supporting Parties: APPrO, BOMA, CME, CCC, EP, ED, FRPO, GEC, IGUA, Kitchener, LPMA, OGVG, PP, QMA, SEC, SNNG, VECC.

Evidence: The evidence in relation to this issue includes, but is not limited to, the following:

8.3.1	Miscellaneous Service Charges
8.2.7.1	Combined Rate Handbook
Exhibit I.8.2	Exhibit 8, Tab 2 Interrogatories
Exhibit I.8.3	Exhibit 8, Tab 3 Interrogatories
8 TC Tr. 23 - 117	Technical Conference Panel 10
JT8.4 - JT8.16	Panel 10 Undertakings

30. Are the proposed Direct Purchase Administration Charge (DPAC) and Distributor Consolidated Billing (DCB) charges appropriate?

Complete Settlement

Parties agree that the proposed DPAC and DCB charges are appropriate.

Supporting Parties: APPrO, BOMA, CME, CCC, EP, ED, FRPO, GEC, IGUA, Kitchener, LPMA, OGVG, PP, QMA, SEC, SNNG, VECC.

Evidence: The evidence in relation to this issue includes, but is not limited to, the following:

applicable parameters will be different, as described above.

The draft Accounting Orders for the agreed deferral and variance accounts are provided at Exhibit O, Tab 1, Schedule 2.

Supporting Parties: APPrO, BOMA, CME, CCC, EP, ED, FRPO, GEC, IGUA, Kitchener, LPMA, OGVG, PP, QMA, SEC, SNNG, VECC.

Evidence: The evidence in relation to this issue includes, but is not limited to, the following:

9.1.1	Deferral and Variance Account Overview
9.1.1.1	Deferral and Variance Account – Description of Existing Deferral Accounts
9.1.1.2	Deferral and Variance Overview – Summary of Proposals for Deferral and Variance Accounts
9.1.1.3	Deferral and Variance Accounts – Proposed Accounting Orders
9.1.1.4	Proposed Deferral and Variance Accounts
9.1.2	Harmonization and Other Proposed Changes
Exhibit I.9.1	Exhibit 9, Tab 1 Interrogatories
Exhibit I.9.2	Exhibit 9, Tab 2 Interrogatories
3 TC Tr. 164 - 216	Technical Conference Panel 11
JT3.26 - JT3.38	Panel 11 Undertakings

32. Is the proposal to close and continue certain deferral and variance accounts and establish new ones appropriate?

Partial Settlement

Parties agree to the following in relation to the new variance accounts proposed by Enbridge Gas:

- Energy Transition Technology Fund Variance Account – to be addressed in Phase 2.

- Rate Harmonization Variance Account – to be addressed in Phase 3.

- Dawn Parkway Surplus Capacity Deferral Account – Parties agree to the creation of a Dawn Parkway Surplus Capacity Deferral Account as proposed, subject to one change. In the event that Enbridge Gas uses surplus Dawn Parkway capacity (forecast at 89 TJ in 2024) to reduce the Parkway Delivery Obligation, then the PDCI costs will be reduced, which will be captured in the Parkway Delivery Obligation Variance Account.

- Open Bill Extension Deferral Account – Parties agree to the creation of this account as proposed.

- Enhanced Distribution Integrity Management Program Variance Account – as described in Issue 12, Parties agree instead to the creation of a new Distribution Integrity Management Program (DIMP) Costs Variance Account. The account will record variances in Enbridge Gas spending each year on the DIMP and EDIMP programs. Parties agree that $12.5 million is included in the 2024 O&M budget for these programs, and that variances will be recovered from or credited to ratepayers on an annual basis from 2024 until Enbridge Gas next rebases. Enbridge Gas will provide annual reporting on actual DIMP/EDIMP spending, setting out the work done (and associated costs), listing the projects/facilities where work was done, describing what facilities work was deferred or avoided or otherwise impacted as a result and discussing the cost/benefit analysis of the DIMP/EDIMP work done during the past year.

- The Post-Retirement True-Up Variance Account will be established as described in Issue 13 above, such that it includes a $10 million deadband for variances from the forecast revenue requirement impact of pension and OPEB costs (accrual and cash-based amounts) embedded in rates ($8.3 million credit in 2024 revenue requirement). Parties agree that where the variance in the revenue requirement of actual pension and OPEB costs (accrual and cash-based amounts) is greater than $10 million compared to the amount embedded in rates in any year from 2024 until Enbridge Gas next rebases, Enbridge Gas may recover (or credit) the actual amount outside of the $10 million deadband from (or to) ratepayers. Other than the addition of a deadband, the Post-Retirement True-Up Variance Account will operate in the manner described in the Enbridge Gas March 8, 2023 update[10].

Additionally, Parties agree that Enbridge Gas will create a new Clean Fuel Regulation (CFR) Credits Deferral Account that will record the revenues obtained by Enbridge Gas from the sale of CFR credits for the benefit of ratepayers. Enbridge Gas will be permitted to also record offsetting credit formation, certification and transaction administration costs in the account. The administration costs eligible for recording and recovery include the following:

- Incremental staffing costs;
- Consulting costs, including but not limited to preparation of monitoring reports and third-party verification of credits;
- Legal costs, including but not limited to preparing contracts for procurement or sale of credits, understanding of the regulation; and
- Other costs such as training/conferences and market monitoring subscriptions (needed to stay abreast of market).

[10] Exhibit 9, Tab 1, Schedule 1, Attachment 3, p.37, Updated March 8, 2023.

As set out at Issue 4, the Parties agree that Enbridge Gas will create a new Indigenous Working Group Deferral Account (IWGDA).

As set out in Issue 9, there is no agreement about whether Enbridge Gas should create a Volume Variance Account.

As part of the OEB's consideration of the unsettled issues in Phase 1, Parties are free to request the establishment of a new deferral and/or variance account, insofar as the proposed account relates to an unsettled (or unsettled components of a partially settled issue) and would not be contrary to a settled issue (or settled component of a partially settled issue).

As advised in Enbridge Gas's letter dated May 24, 2023, Enbridge Gas is no longer seeking a Locate Delivery Services Variance Account as this is being requested on a generic basis by numerous large distributors (gas and electric). In a letter dated June 14, 2023, the OEB requested more information from the requesting utilities (including Enbridge Gas) before making a determination about whether to approve the requested generic account. As stated in the Enbridge Gas letter: "[i]n the event that the OEB declines to address the request for a locates cost variance account on a generic basis, or in a way that takes into account Enbridge Gas's circumstances (which include very significant underground infrastructure), then Enbridge Gas reserves the right to request that this item be re-introduced and determined in Phase 2 of this proceeding".

Supporting Parties: APPrO, BOMA, CME, CCC, EP, ED, FRPO, GEC, IGUA, Kitchener, LPMA, OGVG, PP, QMA, SEC, SNNG, VECC.

Evidence: The evidence in relation to this issue includes, but is not limited to, the following:

9.1.3	Establishment of New Deferral and Variance Accounts
9.1.4	Deferral and Variance Account Closures
Exhibit I.9.1	Exhibit 9, Tab 1 Interrogatories
3 TC Tr. 164 - 216	Technical Conference Panel 11
JT3.26 - JT3.38	Panel 11 Undertakings

33. Is the proposal to dispose of the forecast balances in certain deferral and variance accounts appropriate?

Partial Settlement

With the following two exceptions, Parties agree to the clearance of deferral and variance accounts as proposed by Enbridge Gas.

- Parties do not agree to the clearance of the 2019-2023 balances in the TVDA

TAB 9

AIRD BERLIS

David Stevens
Direct: 416.865.7783
E-mail: dstevens@airdberlis.com

May 24, 2023

BY EMAIL AND FILED VIA RESS

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: Enbridge Gas Inc. ("Enbridge Gas")
EB-2022-0200 – 2024 Rates Application
Withdrawal of Requests for Locate Delivery Charge & Locate Delivery Services VA

We represent Enbridge Gas.

We write to advise the Ontario Energy Board (OEB) and parties that Enbridge Gas is withdrawing its requests for approval of a Locate Delivery Charge[1] and a Locate Delivery Service Variance Account (LDSVA)[2] from the 2024 Rates Application. Instead, the creation of a new locates cost variance account is being pursued on a generic basis, through a joint request with several other large Ontario local distribution companies (LDCs). In the event that the OEB declines to grant the requested relief through that generic process, then Enbridge Gas reserves the right to request that these items be re-introduced and determined in Phase 2 of this proceeding.

In prefiled evidence in this case, Enbridge Gas explained the implications of Bill 93 (*Getting Ontario Connected Act, 2022*), the pertinent provisions of which came into force on April 1, 2023. Among other things, Bill 93 included amendments to the *Ontario Underground Infrastructure Notification System Act, 2012* (the Act) requiring underground infrastructure owners like LDCs to complete locate requests within five days, failing which the LDC is subject to administrative monetary penalties (AMPs) under the Act. This absolute time limit and the penalties for failure to perform at that standard without exception are new legislative requirements.

The cost implications of the new requirements from Bill 93 will impact most or all LDCs in Ontario. These costs are new, and are not included in the base rates / revenue requirement for LDCs. On May 11, 2023, Enbridge Gas and a group of other large LDCs[3] wrote to the OEB to request that the OEB establish generic, sector-wide variance accounts for LDCs to track the incremental costs of locates in 2023 and future years arising from the implementation Bill 93. The LDCs have requested that all incremental costs resulting from the legislation incurred on or after January 1, 2023 be eligible for the variance account. A copy of the May 11, 2023 letter is attached.

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[1] Exhibit 8, Tab 3, Schedule 1, starting at page 13.
[2] Exhibit 9, Tab 1, Schedule 3, starting at page 8.
[3] Enbridge Gas, Alectra Utilities, Elexicon Energy, Hydro One, Hydro Ottawa, Oakville Hydro and Toronto Hydro.

We understand that the OEB will be considering the request set out in the May 11, 2023 letter, and may do so on a generic sector-wide basis. As a result, Enbridge Gas is withdrawing its request for the LDSVA in this 2024 rates proceeding.

Enbridge Gas's plans to introduce new service fees for locates requests have met significant resistance. Enbridge Gas has determined that that it will not charge third parties for locates requests at this time. Therefore, Enbridge Gas is also withdrawing its request for approval of a new Locate Delivery Charge in the 2024 rates proceeding.

In the event that the OEB declines to address the request for a locates cost variance account on a generic basis, or in a way that takes into account Enbridge Gas's circumstances (which include very significant underground infrastructure), then Enbridge Gas reserves the right to request that this item be re-introduced and determined in Phase 2 of this proceeding. Similarly, should circumstances change such that an approved service fee for locates requests becomes necessary for Enbridge Gas, then the Company may choose to pursue that request at a later date.

Please let us know if you have questions about this letter.

Yours truly,

AIRD & BERLIS LLP

David Stevens
DS/
c: All parties registered in EB-2022-0200

May 11, 2023

BY EMAIL

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: Bill 93 (*Getting Ontario Connected Act, 2022*)
Request for Variance Account for Incremental Costs for Locates

We are a group comprised of many of Ontario's large local distribution companies (LDCs).

We write to request that the Ontario Energy Board (OEB) establish generic, sector-wide variance accounts for LDCs to track the incremental costs of locates in 2023 and future years arising from the implementation of recent Provincial legislation: Bill 93 (*Getting Ontario Connected Act, 2022*). The pertinent provisions of the legislation came into force on April 1, 2023. Some LDCs began incurring significant incremental costs in advance of April 1, 2023 in order to meet the new performance standard. Accordingly, we request that all incremental costs resulting from the legislation incurred on or after January 1, 2023 be eligible for the variance account.

This new legislation impacts all of our organizations, and indeed all LDCs in Ontario. Accordingly, and in the interest of regulatory efficiency, our group is making this request through a single letter rather than a series of very similar, individual requests.

Further details regarding this request are provided below.

Bill 93, *Getting Ontario Connected Act, 2022* received Royal Assent on April 14, 2022. Among other things, Bill 93 included amendments to the *Ontario Underground Infrastructure Notification System Act, 2012* (the Act) that are intended to improve the processes and requirements related to determining the location of underground infrastructure, enabling construction activities in the province to be completed faster and more efficiently, without compromising safety.

The amendments to the Act arising from Bill 93 require LDCs to complete locate requests within five days, failing which the LDC is subject to administrative monetary penalties (AMPs) under the Act. This absolute time limit and the penalties for failure to perform at that standard without exception are new legislative requirements. While our organizations continue to support Ontario's intent to modernize the locate industry and remain committed to helping deliver capital investment in the province, including for priority broadband, transit and housing projects, the new expectations will lead to substantial incremental costs.

As a result of legislative and regulatory changes impacting the Act, infrastructure owners, including our organizations, are now making significant incremental investments to fund operational improvements, including hiring and training more locators with the competitive wages required to attract new workers, procuring equipment and vehicles, and improving IT infrastructure. Our preliminary estimates indicate that annual locates costs are likely to increase significantly and by 100% or more, in some cases. While some LDCs have more underground infrastructure than others, the new locates requirements are common to all of us. The costs of these new requirements are not included in our approved rates (or base revenue requirement) because the requirements did not exist and were not contemplated when rates were set on a cost of service basis. The incremental costs are unknown, but are expected to be material (expressed in terms of the OEB's materiality thresholds).

All underground infrastructure owners, including utilities, are required to comply with the Act and its regulations. In order to recover these compliance-related costs, some organizations have proposed to introduce new service fees for certain locate requestors. These plans have been met with significant resistance. Through this letter, our organizations are requesting a variance account, which, subject to the discretion of the OEB, would maintain the status quo of ratepayer cost responsibility for locates costs.

The OEB's Filing Requirements for gas and electricity distributors include similar expectations where a new variance account is requested.[1] Where an applicant seeks an accounting order to establish a new variance account, the request must be accompanied by evidence of how the following eligibility criteria will be met:

- Causation – The forecasted expense must be clearly outside of the base upon which rates were derived.
- Materiality – The forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements.
- Prudence – The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition.

Each of these criteria are met here.

- Causation – No LDC's current rates (or the base upon which those rates are set) include the Bill 93 related locates costs. The costs related to locates recovered through each LDC's existing rates reflect the previous, less costly, legal framework.
- Materiality – Preliminary estimates of the variance between the actual costs for locate delivery services, and the amount included in rates will exceed the materiality threshold for the establishment of new deferral and variance accounts.[2]
- Prudence – The costs to provide legislatively mandated locate services according to a legislated standard are reasonably incurred.

[1] See Filing Requirements Natural Gas Rate Applications, section 2.9.2, page 38; and Filing Requirements for Electricity Distribution Applications, section 2.9.2, page 66.

[2] For the organizations making this request, the materiality threshold is as follows: 0.5% of revenue requirement for a utility with a revenue requirement greater than $10 million and less than or equal to $200 million; and $1 million for a utility with a revenue requirement of more than $200 million.

Draft accounting orders for the requested locates delivery services costs variance account for electricity LDCs and for Enbridge Gas can be provided as required. Each LDC will provide detailed support for the account balance as part of their appropriate deferral account disposition proceeding where clearance is requested.

For electricity LDCs, we request that the new variance account be effective starting on January 1, 2023, and continue until electricity LDCs rebase, at which point future incremental locates costs will be incorporated into revenue requirement. We request that LDCs be eligible to seek disposition of the variance account in according with standard OEB rules.

The context for the request by Enbridge Gas is slightly different, because Enbridge Gas has already made a request for a locates charge and a deferral account for 2024 to track the difference between actual costs and the revenue collected through the proposed locate charge within its ongoing 2024 Rates/Rebasing Application (EB-2022-0200).[3] As set out in this letter application, Enbridge Gas is now seeking the establishment of a variance account starting January 1, 2023 for incremental locates services costs. Enbridge Gas intends to make a request in its rebasing case, asking that the OEB remove its proposal for a locates charge and the locates deferral account from the current phase 1 of the rebasing proceeding.

Should you have any questions, please contact Mark Kitchen at 416-495-5499 or via email at EGIRegulatoryProceedings@enbridge.com.

Sincerely,

Christine Long
Vice President, Regulatory
Affairs & Privacy Office
ALECTRA

Stephen Vetsis
Vice President
Regulatory Affairs and
Stakeholder Relations
ELEXICON ENERGY

Mark Kitchen
Director,
Regulatory Affairs
ENBRIDGE GAS

Frank D'Andrea
Vice President,
Regulatory Affairs
HYDRO ONE

April Barrie
Director,
Regulatory Affairs
HYDRO OTTAWA

Scott Mudie
EVP, Chief Energy
Transformation Officer
OAKVILLE HYDRO

Andrew Sasso
Director,
Energy Policy & Government
Relations
TORONTO HYDRO

[3] The Enbridge Gas request for a Locate Delivery Service Variance Account is set out at Exhibit 9, Tab 1, Schedule 3, page 8 of the EB-2022-0200 filing.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 19, pp. 2-4

Question(s):

a) Please explain why the "HR Burden and Benefits" ($1.9M) in Table 2 do not form part of amounts paid by Enbridge Sustain to Enbridge Gas for services (as shown in Table 1). As part of the response, please further explain that the statement that these costs "were charged through CFCAM to EGI regulated Line of Business (LOB) and then pass through to the Enbridge Sustain LOB."

b) Please provide the fully allocated cost rates applied to the labour hours shown in Table 2. As part of the response, please also provide an explanation regarding how the fully allocated cost rates were derived.

Response:

a) Benefits are centrally managed costs which include pension and OPEB, short-term (STIP) and long-term (LTIP) incentive pay and health and other employee benefits for Enbridge employees. Prior to Enbridge Sustain being established as an affiliate, the benefits costs for full-time employees working for Enbridge Sustain were allocated to Enbridge Gas under the Central Function Cost Allocation Methodology (CFCAM). Because CFCAM allocates benefits costs only to the regulated line of business (LOB) within Enbridge Gas, a pass-through adjustment was required to remove these costs from the utility and reassign them to Enbridge Sustain, as though CFCAM had originally allocated the benefits costs directly to Enbridge Sustain. As of January 1, 2025, following Enbridge Sustain's transition to an affiliate, all benefits costs are allocated directly to Enbridge Sustain from Enbridge Inc.

   This pass-through adjustment was calculated using a weighted-average HR burden rate consistent with the methodology approved in 2024 Rebasing Phase 1[1]. Using the weighted-average HR burden rate ensures that no portion of Enbridge Sustain driven benefits costs are borne by the utility or its ratepayers and that Enbridge Sustain is allocated appropriate costs.

[1] EB-2022-0200, Exhibit 2, Tab 4, Schedule 2, pp.12-14.

These costs are not included in the amount paid by Enbridge Sustain to Enbridge Gas for services because they relate solely to full-time Enbridge Sustain employees and benefits costs for those employees. In substance they are no different than the salaries and wages direct costs charged directly to Enbridge Sustain, it is simply that an extra accounting related step was taken to charge the costs to Enbridge Sustain (i.e. in and out of the utility on a flow through basis).

b) Fully Allocated Cost (FAC) is the combined sum of direct and allocable indirect costs related to a designated activity. FAC rates are calculated on an hourly basis, determined by salary grade and available annual work hours.

Direct costs encompass the total compensation for an EGI employee, including benefits, and are calculated on an average basis according to salary grade.

Indirect costs comprise the administrative and intermittent support from departments not directly attributed to the activity. These costs are uniformly applied as a flat charge, across all salary grades. The flat indirect charge is comprised of two components, 1) Employee Supporting, and 2) Equipment, Facilities, and IT, determined as follows:

1) Employee Supporting - Total annual cost of Enbridge Gas departments that directly support employees, divided by the total full time employees (FTEs) at Enbridge Gas. The departments identified as providing direct support are Human Resources, Workplace Services, Safety, and IT.

2) Equipment, Facilities, and IT - Total annual depreciation expense, property tax and return on average net book value of all Enbridge Gas buildings, office furniture, IT equipment and software, divided by the total FTEs at Enbridge Gas.

This indirect value, coupled with the average compensation and benefits value for the respective grade of employee providing service to an affiliate, forms the basis for FAC. The FAC values by salary grade are converted into hourly rates using the available annual work hours.

The 2024 FAC rates are included in Table 1.

Table 1

Enbridge Gas Inc.
2024 Fully Allocated Cost Hourly Rates for Intercorporate Services Agreements

Line No.	Salary Grade	2024 Hourly Rate
1	Union	$114
2	E310	$98
3	E320	$102
4	E400	$109
5	E410	$116
6	E420	$127
7	E500	$143
8	E510	$157
9	E600	$206
10	E700	$343
11	E800	$539
12	E810	$866

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, pp. 1-2

Question(s):

Please further explain the inclusion of the 2022 ESM/DVA disposition and 2024 Rebasing DVA disposition amounts in the calculation of 2024 S&TDA balance sought for disposition in the current proceeding.

Response:

Prior to rebasing in 2024, the cost of Dawn Parkway System transportation was charged to the EGD rate zone by the Union rate zone. These costs were treated as gas supply costs, with cost variances recorded in the EGD S&TDA.

As a customer of the Union rate zone under rate M12 and M16, EGD was allocated a portion of the balances disposed of in 2022 ESM/DVA and 2024 Rebasing DVA proceedings, which have been recorded in the 2024 S&TDA balance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 2, p. 1
Exhibit B, Tab 2, Schedule 3

Question(s):

a) Please provide a more detailed version of Table 1 showing the calculation of each of the revenue and cost line items.

b) Please explain why the costs are considered “deemed” costs.

c) Please explain each of “shared” revenues & costs and “standalone” revenues & costs.

d) Please explain why Line 10 (Total Costs (B)) is described as “net OBA” revenue in Exhibit B, Tab 2, Schedule 3.

e) To the extent that $9.556 million reflects the net OBA revenues, why is that not the amount that is subject to refund to ratepayers through the Open Bill Extension deferral account.

Response:

a) A more detailed version of Table 1 showing a calculation of each of the revenue and cost line items is as follows:

Table 1
Open Bill Extension - 2024 Net Revenues

Line No.	Particulars	# of Bills	Rate per bill	Amount
1	Revenue			
2	Shared	8,791,796	$ 1.148	$ 10,092,982
3	Standalone	219,823	$ 2.630	$ 578,134
4	Bad Debt recovery (0.52% of billed receivables)			$ 1,950,854
5	Total Revenues (A)			$ 12,621,970
6	Deemed Costs			
7	Shared	8,791,796	0.8134	$ 7,151,247
8	Standalone	219,823	2.0559	$ 451,934
9	Bad Debt expense			$ 1,952,353
10	Total costs (B)			$ 9,555,534
11	Net Revenues Deferred to Ratepayers (A-B=C)			$ 3,066,436

b) The deemed Open Bill Access (OBA) Program costs are equal to the number of bills with Open Bill charges times the OEB-approved unit cost per bill. As per the OEB Decision on the Open Bill Access Settlement Agreement[1], the OEB-approved unit cost per bill was approved for the period from 2014 to 2018. As of 2018, the OEB-approved unit cost per bill was $0.7195 per shared bill and $1.8186 per standalone bill. Since that time, the OEB-approved unit cost per bill has been increased by CPI each year (capped at 2.5%).

c) The OBA program would allow third parties to charge their customers directly by adding their charges to the Enbridge Gas bill. The term “shared” refers to bills which include Distribution Charges and “standalone” refers to bills that do not include Distribution Charges.

[1] EB-2013-0099, OEB Decision on Settlement Agreement Open Bill, September 13, 2013.

d) OBA program revenue of $9.6 million, as shown in Exhibit B, Tab 2, Schedule 3, is referred to as net OBA revenue as it reflects gross program revenues of $12.622 million net of transferring $3.066 million to the Open Bill Extension Deferral Account (OBEDA). The $3.066 million transferred to the OBEDA reflects net program revenues, calculated as gross program revenues of $12.622 million less deemed program costs of $9.556 million. As a result, Enbridge Gas retains revenues equivalent to its deemed costs and then passes on the remaining $3.066 million on to ratepayers. Enbridge Gas acknowledges that footnote 1 in Exhibit B, Tab 2, Schedule 3 could have been more clear. The footnote could have been phrased to explain that the Open Bill Access Revenue “Represents OBA revenue after transferring net OBA program revenues to the Open Bill Extension Deferral Account for credit to ratepayers (after net program revenues are credited to ratepayers, OBA revenues recorded are equal to the deemed costs of the OBA Program). Please see Exhibit D, Tab 1, Schedule 2 for details of total revenue, deemed costs and amount deferred in Open Bill Extension Deferral Account.”

e) The $9.556 million highlighted in Exhibit B, Tab 2, Schedule 3, page 1 reflects the amount of Open Bill Access Revenue after transferring $3.066 million to the OBEDA. Total Open Bill revenues in 2024 were $12.622 million and total Open Bill costs were $9.556 million. The net program revenue of $3.066 million that accrued to the benefit of ratepayers was transferred from revenue to the OBEDA. As noted in d) after transferring the net program revenue attributable to ratepayers to the OBEDA, $9.566 million remains in Other Revenue which is offset by an equivalent program cost amount. The net revenues are determined by subtracting OBA Program costs from revenues. Under this approach, the OBA Program net revenues are determined each year by subtracting the deemed OBA Program costs from the OBA Program revenues received by the Company from Billers. The difference for 2024 (the final year) is that all OBA Program net revenues are credited to ratepayers, as compared to prior years where only new revenues above a threshold were shared.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, p. 2

Question(s):

Please explain how Enbridge Gas sought to minimize UDC costs incurred and maximize revenues from released capacity in 2024.

Response:

Please see response at Exhibit I.STAFF-14 part b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit F, Tab 1, Schedule 1, pp. 8-9

Question(s):

With respect to the Union South rate zone, please advise whether the billing adjustment of $16.56 is a monthly billing adjustment applied for three months or $5.52 is the monthly billing adjustment that will be applied for three months.

Response:

For Rate M1 sales service residential customers in the Union South rate zone with annual consumption of 2,200 m^3, Enbridge Gas has proposed to dispose of the total billing adjustment charge of $16.56 over three months, for a monthly amount of approximately $5.52 per month.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, p. 1, 3 of 4.

Preamble:

At page 1, EGI stated that "After removing 2024 severance from actual O&M, Enbridge Gas was relatively flat to 2024 OEB approved." EGI stated at page 3 that there was approximately $20 million in STIP and legislative benefits.

Question(s):

a) Were there any other drivers of higher-than-expected O&M for the remaining workforce (after headcount reductions) other than STIP and legislative benefits?

b) Please describe why EGI was required, or determined it was appropriate to provide 20 million in extra STIP and legislative benefits beyond what was forecast in rates.

Response:

a) Yes, the other compensation related driver of higher than expected O&M is long term incentive benefits (LTIP) which are approximately $2.8 million.

b) As noted in the 2024 Rebasing Phase 1 proceeding[1], Enbridge Gas provides competitive total compensation that includes base pay, incentive plans, benefits and pensions for all employees. Short term incentive benefits (STIP) is a yearly cash incentive that rewards performance at the enterprise, business unit, and individual levels, with weightings based on role impact. It aligns employee goals with company priorities, and everyone participates.

   Rates were established on the basis that Enbridge Gas would achieve target STIP performance, whereas actual STIP payout is based on achieved 2024 performance that exceeded the target performance.

[1] EB-2022-0200, Exhibit 4, Tab 4, Schedule 3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 2, page 5 of 8.

Preamble:

At page 4, EGI stated "First is the reprioritization of investments based on funding the most urgent, near-term requirements of the system, and reducing scope of projects to focus on component and partial replacements. The second reason is the completion or re-pacing of several large customer-driven projects."

Question(s):

a) Prior to the ordered reduction in capital spending, did EGI give consideration to component and partial replacements? If the answer is no, explain why not, if the answer is yes, explain how EGI has changed its approach to partial or component replacements as compared to the previous capital planning process before the capital reduction.

b) Please provide a list of large customer driven projects that were re-paced, and the overall impact of the re-pacing on the capital budget.

Response:

a) Yes, prior to the OEB ordered $250 million reduction in the 2024 capital budget, Enbridge Gas had historically incorporated component and partial asset replacements as part of its asset management framework. Specifically for the Growth asset class, Enbridge Gas focused on capital funding for the most urgent near-term projects or installing CNG as a short-term partial solution. The underlying requirement of the system that drove the initial capital plan will not go away, and a reduction in the capital spend near term combined with the continued use and potential growth of the system may result in higher capital requirements in the future.

b) Table 1 provides a list of projects that were re-paced due to changes in customer requirements:

Table 1
Re-paced Projects

Line No.	Project Name	Variance '23 vs '24 Actuals
1	Hamilton Reinforcement Project	($800K)
2	Grimsby-Lincoln Expansion Project - Natural Gas Expansion Program (NGEP)	($100K)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, p. 2 of 6.

Question(s):

Please confirm CME's understanding that the harmonization of UFG volumes for the Union rate zone therefore represents a timing difference of being affected by 2023 and 2024 adjustments simultaneously, and that now that it is on the harmonized methodology, that increase will recur in the future. If that's not confirmed, please explain the reason why it would recur.

Response:

Not confirmed.

The adjustments for unbilled and no billed estimates for the Union rate zone for December 2023 rolled into the 2024 UFGVVA balance. Because of the harmonized methodology adopted in 2024, the adjustments for unbilled and no billed estimates for the Union rate zone for December 2024 were also recorded in the 2024 UFGVVA balance. As such, in 2024, the UFGVA balance was impacted by the year end true-up for 2023 and the year end adjustment for 2024. This is a one-time impact as a result of harmonization in 2024. Going forward, the UFGVVA will only be impacted by the year-end adjustment for the discrete fiscal year that it pertains to.

Please see response at Exhibit I.FRPO-8 for a detailed explanation of the unbilled and no billed adjustments.

For additional clarity, these adjustments will not always create increases and are merely meant to eliminate the temporary UFG volatility that occurs as a result of these estimates, as described in the response at Exhibit I.FRPO-10.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, p. 2 of 6.

At page 4, EGI stated that "The impact of the December 2023 unbilled and no-bill estimates (as was the previous practice) on 2024's UFGVVA was an increase in UFG recorded in the variance account of approximately 21,049 103 m3. The impact of the December 2024 unbilled and no-bill estimates was an increase of 63,948 103 m3."

Question(s):

Has Enbridge investigated why the increase in UFG changed so drastically between 2023 (21K) and 2024 (63K) as a result of unbilled and no-billed estimates? What is the reason?

Response:

Yes, Enbridge Gas has investigated the increase in UFG as a result of unbilled and no billed estimates between 2023 and 2024. Enbridge Gas has determined that the level of accuracy of the unbilled and no billed estimates, calculated as estimated volumes vs. actual billed volumes, measured as a percentage, is similar in both years. However, the weather for December 2024 was significantly colder relative to December 2023. As such, the unbilled and no billed estimates, in total, were higher in December 2024, with a corresponding increase in the variance between estimated and billed volumes for that time period.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, p. 4 of 6.

At page 4, EGI stated "The new 2024 Benchmark Analysis, represented in Figure 2, recognizes the relative size of each utility within a comparator group by determining the groups weighted average UFG by volume of throughput."

Question(s):

a) Was ScottMadden asked to opine on whether or not the analysis of UFG volumes should be weighted by volume of throughput? If so what was their response, if not, why not?

b) Other than any consultations with ScottMadden, did EGI conduct any analysis to determine if throughput volume average weighting was appropriate in this circumstance?

c) Figure 2 at page 5 shows sharp changes to year over year UFG amounts. UFG can be impacted by billing issues, such as when estimated reads underestimate the actual consumption. Has EGI ever conducted any analysis to correlate the UFG with increases or decreases in estimated meter reads?

Response:

a-b) ScottMadden was not asked to opine on Enbridge Gas's updated benchmarking analysis, which recognizes the relative size of each utility within a comparator group. The analysis was done to provide more context on UFG trends across North America. The Company did not believe that it was necessary to re-engage ScottMadden for this work, which could be done in-house. Enbridge Gas did no additional analysis on the change to the presentation of the benchmarking results, but continues to believe that it is appropriate to adjust for the size of other utilities in considering their UFG results.

c) Enbridge Gas is investigating the potential impact of meter read estimates on UFG and believes it is possible that the industry standard practice of billed estimates increases short-term UFG volatility due to the nature of point in time UFG reporting. Please see the response at Exhibit I.STAFF-1 parts a) and c) for more details.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, p. 5, Figure 2, page 6

Figure 2 demonstrates that at least to some degree, many of the utilities captured in the study experience similar trends year over year. At page 6 of 6, EGI stated that “common macroeconomic factors or national/continental weather trends” could be the reason for the industry-wide trends.

Question(s):

What sort of macroeconomic factors or weather would cause changes to UFG? Is EGI’s statement simply a matter referring to total throughout of gas (either due to colder/warmer weather and consumer purchasing volumes)? Or are there other impacts either of economic conditions or weather which might impact UFG (such as colder weather causing additional leaks in physical pipe infrastructure)?

Response:

The statement refers to the impact of factors such as variations in weather, economic growth, the availability of supply, and market price on the throughput of natural gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 5, p. 1.

On Page 1, EGI stated: "Disposition variances result from Enbridge Gas's billing systems' inability to locate and apply deferral clearance unit rates to all intended customers and/or volumes. Due to customer moves and other account changes, deferral clearance unit rates derived utilizing historical customers and volumes are not able to be assessed against all historical customers and/or volumes at the time of disposition, resulting in the balances captured in the Deferral Clearing Variance Account."

Question(s):

Will the amounts credited to ratepayers be allocated to the customer classes within which the original customers took service? Or will the amounts credited be allocated to rate classes in a different fashion? If the latter, please explain the allocation methodology.

Response:

No, the balance included in the harmonized Deferral Clearing Variance Account is not allocated to rate classes based on where the original customers took service. Enbridge Gas is proposing to allocate the balance in the harmonized Deferral Clearing Variance Account to in-franchise rate classes in proportion to actual annual throughput volumes. The proposed methodology is consistent with methodology approved by the OEB for the Deferred Rebate Account in the EGD rate zone and the Deferral Clearing Variance Account in the Union rate zones in Enbridge Gas's 2023 Utility Earnings and Disposition of Deferral & Variance Accounts proceeding[1].

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[1] EB-2024-0125.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 6, p. 1-3

At pages 1-3, EGI stated that it was “not able to shift any PDO in 2024”. EGI also stated that “In 2025, Enbridge Gas will continue to consider practical market-based solution alternatives to PDO, and as part of that consideration Enbridge Gas will be issuing an RFP for an exchange from Parkway to Dawn or Kirkwall to Dawn.”

Question(s):

a) Was an RFP for an exchange from Parkway to Dawn or Kirkwall to Dawn implemented in 2024? If so, please explain if EGI thinks that it would be more successful in 2025.

b) If an exchange was not implemented in 2024, please explain why not.

Response:

Please see the response at Exhibit I.STAFF-3 part d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 7, p. 1 of 3; Exhibit C, Tab 2, Schedule 14.

CME would like to better understand the interactions of accounts 179-305 and 179-328. At Schedule 7, EGI stated "The forecast accrual reference amount that will be used to calculate the entries recorded assumes that the total gross accrual cost as determined by actuarial valuation is what is recorded in the Company's total operating and maintenance expense. The actual cash payments would include all cash payments the utility makes for its pension and OPEB obligations. The approved accrual amount in rates will not change or escalate during the IR term."

EGI stated at Schedule 14 that account 179-328 "records the difference, in excess of a $10 million deadband (debit or credit), between the revenue requirement impact of actual pension and other post-employment benefits (OPEB) costs (accrual and cash-based amounts) and the revenue requirement impact of pension and OPEB costs (accrual and cash-based amounts) included in rates.

Question(s):

a) Please confirm whether the actuarial valuation of accrual costs corresponds to the accrual amount used to forecast the revenue requirement impact of accrual pension and OPEB costs in account 179-328 or not.

b) If not confirmed, please explain what is used to forecast the accrual costs if not the actuarial valuation, and why it is appropriate to use two different forecasts.

c) Would account 179-328 capture the variances described between the actuarial valuation and what is recorded in the Company's total operating and maintenance expense? Please explain fully.

d) Are the credits/debits in account 179-305 ever trued up between the actuarial valuation and the actual recorded operating and maintenance expense?

<u>Response:</u>

In terms of reference, account 179-305, the Pension and OPEB Variance Account, tracks the cumulative difference between the forecast accrual pension and OPEB amount recovered in rates and the actual cash payments made, and where cumulative recoveries exceed payments a carrying charge accrues to ratepayers. By comparison, account 179-328, the Post Retirement True-Up Variance Account, captures the variance between the annual revenue requirement impact of actual pension and OPEB costs and revenue requirement impact of pension and OPEB costs in rates.

a-b) The Company confirms that the forecast of 2024 accrual based pension and OPEB expense ($1.6 million credit), as determined by actuarial valuation at the time of the rebasing application, is leveraged in the determination of amounts recorded in both accounts 179-305 and 179-328. In 179-305, the 2024 accrual amount reflected in rates, as shown at Line 1 of Table 1 within Exhibit C, Tab 2, Schedule 7, is compared against actual 2024 cash pension and OPEB payments. In 179-328, the 2024 accrual amount reflected in rates, as shown at Line 8, Column B of Attachment 1, within Exhibit C, Tab 2, Schedule 14, is a component of the base 2024 pension and OPEB revenue requirement against which the actual 2024 pension and OPEB revenue requirement is compared.

c) Yes, the variance between 2024 actual accrual based pension and OPEB expenses, as reflected in actual utility operating and maintenance expenses, and the forecast of 2024 accrual based pension and OPEB expenses, as determined by actuarial valuation at the time of the rebasing application, is captured as part of the revenue requirement variance captured in account 179-328. In addition to the variance between the actual and approved forecast accrual based pension and OPEB costs, the revenue requirement variance captured in account 179-328 also captures the impact of income tax variances attributable to actual versus forecast cash pension and OPEB amounts which are deductible for tax purposes.

d) No, the OEB approved credit in rates of ($1.6) million (i.e. the forecast of 2024 accrual based pension and OPEB expenses, as determined by actuarial valuation at the time of the rebasing application) used in the calculation for account 179-305 is not trued up to actuals as recorded in actual operating and maintenance expense. The intent of account 179-305 is to track the variance between the forecast accrual based pension and OPEB expenses reflected in rates and the corresponding revenues and cash recoveries of Enbridge Gas, versus the actual cash outlays for pension and OPEB's in an effort to determine if the Company is realizing any inherent financing benefit. The variance between the actual accrual based pension and OPEB expense recorded in operating and maintenance expenses, and the forecast accrual based pension and OPEB expense reflected in rates, does not impact the revenue or cash recovered by Enbridge Gas, not taking into account any potential impact that may be realized as a result of recognizing amounts in account 179-328.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 8, p. 4 of 5

At page 4, EGI stated: "Enbridge Gas still has the option to satisfy its 2024 EPS obligation by purchasing EPUs from other EPS participants. EPUs typically sell at a discount to the excess emissions charge, which would reduce Enbridge Gas's 2024 EPS compliance obligation."

EGI also stated that "EPP funding is equal to a facility's compliance payment made to the provincial government in the previous year."

Question(s):

We reviewed Staff-2 in EB-2024-0251 and have the following additional questions:

a) Is the EPP funding available cumulative for each facility, or is it forfeited if not used in one year?

b) To the extent that EPP funding is not cumulative, and disappears at the end of each year. Please provide the amount of money that was available through the EPP that was not used by EGI since the program started (2024) broken out by regulated facility.

c) If EPUs are purchased in one year, and therefore reduce the EPP funding for the following year, is there any bar to EGI paying the compliance charge for more of its EPS compliance obligation, thereby increasing the funding available in future years after the initial reduction?

d) How does EGI's planning department plan projects to coincide with compliance funding? For instance, will EGI specifically pay for more of its compliance charges rather than EPUs for certain facilities in preparation for using the EPP funding to pay for specific projects?

e) Please provide an example of a facility where EGI has used EPP funding on emission reduction projects, the amount of emissions reduced as a result of the projects, and the reduction in compliance costs as a result.

f) Is there any difference between purchasing EPU's or paying compliance obligations on behalf of the regulated or unregulated business? If so, please describe the differences.

Response:

a-b) Emissions Performance Program (EPP) funding is cumulative and remains available in subsequent years for projects that meet eligibility requirements and are approved by the Ministry of Environment, Conservation and Parks (MECP). Enbridge Gas has not forfeited any potential funding.

c) The EPS has no restrictions on the number of excess emission units (EEUs) that may be used by a covered facility to meet its annual obligation and therefore Enbridge Gas can satisfy its entire compliance obligation with EEUs and is not required to achieve compliance by other means (i.e., purchase of emission performance units (EPUs)).

d) Enbridge Gas first seeks to reduce the cost of compliance through procurement of EPUs. The ability to procure EPUs depends on market availability. The remaining available funding can be used toward GHG reduction opportunities. The project opportunities are then evaluated against the funds that are available from the EPP.

e) To date Enbridge Gas has not used EPP funding on an emission reduction project.

f) No, there is no difference in how Enbridge Gas meets the compliance obligation for the regulated or unregulated business.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 9, page 3 of 6

At page 6, EGI stated "The variances recorded are due to deliveries of renewable natural gas (RNG) and hydrogen to customers from 2022 to 2024, through the Company's OptUp program and Low Carbon Energy Project (LCEP), respectively".

Question(s):

As CME understands it, the OptUp program is a voluntary program whereby customers choose to pay a premium to purchase low carbon energy. Please confirm that EGI is proposing to refund the credit for the overcharge of federal carbon amounts to all customers, rather than the specific customers who opted into the OptUp program and paid the premium for low carbon gas.

Response:

Partly confirmed. The federal carbon charge savings related to the OptUp program are recorded in the Customer Carbon Charge Variance Account and credited to customers who are subject to the federal carbon charge (not solely the OptUp program participants). This is consistent with the OEB's direction when the OptUp program was approved.[1]

[1] EB-2020-0066, OEB Decision and Order, September 24, 2020, pp.16-17.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 18, p. 6 of 6.

At page 6, EGI stated “In 2021 and 2022, Enbridge Gas averaged $3.2 million in actual spend on VMS for high risk locates. Following the implementation of Bill 93, annual expenditures have risen to $8.3 million in 2023 and $9.3 million in 2024.”

Question(s):

a) Has EGI seen additional market entrants entering the locate market to take advantage of the increase in market prices?

b) Has EGI explored any opportunities to complete this work in house to reduce the cost of locates? Why or why not?

Response:

a) Enbridge Gas has not seen additional market entrants entering the locate market.

b) Pipeline locating demand is highly seasonal; it’s not practical to maintain a full-time internal workforce year-round, which is why the Company relies on outsourced services to scale up during peak periods. Enbridge Gas currently uses four different locate contractors, which promotes healthy competition and ensures competitive pricing and performance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, pages 2 and 3

Preamble:

Energy Probe is concerned that the number of estimated bills has an impact on UFG.

Question(s):

Please add a column to Table 1 Historical UFG Volumes for EGI (Regulated) that shows the number of estimated bills.

Response:

Please see Table 1.

Table 1
Historical UFG Volumes for EGI (Regulated)

Line No.	Particulars	UFG Volumes (10^3 m^3)	Estimated Bills[1]
1	2013	199,833	
2	2014	225,027	
3	2015	137,110	
4	2016	250,923	
5	2017	190,881	
6	2018	266,362	
7	2019	263,407	
8	2020	177,291	
9	2021	342,549	2,177,164
10	2022	480,301	2,146,394
11	2023	192,110	2,081,710
12	2024	334,888	2,252,790

Notes:
(1) inclusive of the bi-monthly expected estimates

Table 1 has been updated to include the number of estimated bills in December for the years 2021 to 2024. Data prior to system integration in 2021 is not readily available.

Estimated billing does not contribute to long-term UFG. Where estimated consumption differs from actual usage, UFG may be temporarily created, resulting in short-term volatility which is trued-up once an actual meter read is obtained.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 4, page 1

Preamble:

"During 2024, the Company purchased 163,569 103m3 of gas supply in EGD rate zone related to actual UFG volumes on behalf of ratepayers."

Question(s):

Were these purchases combined with other purchases of gas supply? If the answer is yes, is the 163,569 103m3 volume just an allocation?

Response:

Yes, the purchase of actual UFG volumes is combined with other gas supply purchases. The regulated UFG volume of 163,569 10^3m^3 for the EGD rate zone is an allocation based on the actual UFG experienced by EGD rate zone and Union rate zone. Please see Table 1 for the regulated UFG volume allocated by the two rate zones.

Table 1

Allocation of Regulated UFG Volume by Rate Zone

Line No.	Particulars	EGD Rate Zone	Union Rate Zone	EGI
		(a)	(b)	(c)
1	Total Utility and Non-Utility UFG Volume (10^3m^3)	181,861	190,478	372,339
2	Percentage of UFG Volume by Rate Zone	49%	51%	100%
3	Total Regulated UFG Volume (10^3m^3)			334,888
4	Regulated UFG Volume Allocated by Rate Zone (10^3m^3) (1) (2)	163,569	171,319	334,888

Notes:

(1) Line 4 column (a) = Line 3 column (c) x Line 2 column (a)

(2) Line 4 column (b) = Line 3 column (c) x Line 2 column (b)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 18, Page 4

Preamble:

The screening centre has resulted in $991K in locate savings in 2024.

Question(s):

a) Please explain how the $991K amount was calculated.

b) Does that amount include VMS locates?

Response:

a) The $991 thousand amount was calculated by comparing the cost of completing a field locate to the cost of completing a desk screening. The saving was multiplied by the volume of locates screened.

b) The amount does not include VMS locates. By nature, VMS locates would require a field visit and not be screened in office.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit F, Tab 1, Schedule 1, Page 3, Paragraph 9

Preamble:

"The 2024 Pension and OPEB Variance Account balance is a credit of $6.563 million, which consists entirely of interest. Enbridge Gas proposes to split the balance between the EGD and Union rate zones in proportion to actual 2018 OEB-approved rate base."

Question(s):

Please explain why splitting the balance between the EGD and Union rate zones in proportion to actual 2018 OEB-approved rate base is preferable to splitting the balance proportional to the number of employees.

Response:

Enbridge Gas is proposing to split the balance in the 2024 Pension and OPEB Variance Account between the EGD and Union Rate Zones in proportion to the actual 2018 OEB-approved rate base. The proposed methodology aligns with the allocation of the balances in this deferral account to rate classes by rate zone, which is done in proportion to the OEB-approved 2018 rate base[1] for the EGD Rate Zone and the OEB-approved 2013 rate base[2] for the Union Rate Zone.

Enbridge Gas does not support splitting the balance proportional to the number of employees for several reasons:

- The number of employees has not been previously used by EGD or Union as a cost allocation methodology for the disposition of deferral balances.
- In 2018, employees were categorized as part of the EGD rate zone, Union rate zone or Central Functions. There are challenges in determining how central function employees would be allocated in the derivation of the allocation factor.

[1] EB-2017-0086.
[2] EB-2011-0210.

Effective 2019, employees are no longer categorized as being part of the EGD or Union rate zones and are categorized as Enbridge Gas and Central Functions.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 1, Table 1, QRAM's Exhibit C, Tab 1, Schedule 1
& EB-2024-0125 Exhibit I.FRPO-2,3

Preamble:

In the referenced interrogatory responses from the 2023 deferral account preceding EGI provided a monthly breakdown of Optimization revenues from 2022 and 2023.We would like to understand better the utilization of asset rights and the determination of the bottom-line benefits to shareholders and ratepayers.

Question(s):

Please extend the table for 2024 results for only the transportation-based Waddington exchanges and Other Transportation (i.e., not storage) for each of EGD and UGL optimizations separately.

Response:

Please see Table 1 for 2024 transactional services optimization revenue detail.

Table 1
2024 Monthly Transactional Services Optimization Revenue

Line No.	Month ($ millions)	Union Rate Zones Other Transportation	Union Rate Zones Waddington Exchanges	EGD Rate Zone (1) Other Transportation	EGD Rate Zone (1) Waddington Exchanges
		(a)	(b)	(c)	(d)
1	January	0.4	0.9	0.1	11.2
2	February	0.3	0.9	0.1	10.0
3	March	0.2	0.9	0.1	9.5
4	April	0.2	-	0.2	0.1
5	May	0.3	-	0.1	-
6	June	0.3	-	0.1	0.1
7	July	0.3	-	0.2	0.1
8	August	0.3	-	0.1	-
9	September	0.3	-	0.1	-
10	October	0.2	-	0.1	0.1
11	November	0.6	0.4	0.1	6.7
12	December	0.7	0.4	0.2	7.4
13	Total	4.0	3.4	1.5	45.2

Note:
(1) As the Company's financial accounting systems report the revenue detail requested on a customer-specific basis and not by path, Enbridge Gas has made best efforts to provide the information requested (by path) for 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 1, Table 1, QRAM's Exhibit C, Tab 1, Schedule 1
& EB-2024-0125 Exhibit I.FRPO-2,3

Preamble:

EGI's IRR FRPO-3 stated: *In 2023, the Company was able to generate more transactional services optimization revenue using EGD Rate Zone assets compared to Union Rate Zones assets as:*

- *Exchanges transacted using EGD Rate Zone assets are higher on TCPL's Priority of Service; and*
- *The EGD Rate Zone holds more assets that enable firm transportation to and diversion of transportation volumes to Waddington.*

Question(s):

In a second table, please provide the percentage of gas exchanged by path (or point to point exchanges) for each month (e.g., Waddington exchanges – Empress to Iroquois, Dawn to Iroquois, Parkway, to Iroquois, etc.) for each delivery location.

a) Please explain the above two bullets with reference to the specific paths or point-to-point exchanges provided

Response:

Please see Attachment 1.

a) Enbridge Gas has the ability to nominate Firm Transportation (FT) services to the EGD rate zone and Union rate zones using its FT contracts on the TransCanada Mainline from Empress to its respective delivery areas for which the contract relates. Within the EGD rate zone portfolio of contracts, a portion of the Dawn-Waddington path shown in line 2 of Attachment 1 is firm.

Enbridge Gas’s contracts also allow Enbridge Gas to nominate to all other delivery areas using diversions or interruptible transportation services which are not firm and have a higher risk of curtailment relative to FT.

2024 Percentage of Gas Exchanged by Path

		January		February		March		April		May		June	
Line No	Path	Union Rate Zones	EGD Rate Zone	Union Rate Zones	EGD Rate Zone	Union Rate Zones	EGD Rate Zone	Union Rate Zones	EGD Rate Zone	Union Rate Zones	EGD Rate Zone	Union Rate Zones	EGD Rate Zone
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
									0				
1	Parkway-Waddington	27%	21%	26%	29%	3%	2%	1%	9%				6%
2	Dawn-Waddington		38%		34%		25%		7%		1%		4%
3	Parkway-Union EDA	3%		3%		0%							
4	Parkway-Union SSMDA	0%		0%		1%		3%		3%		2%	
5	Union EDA-Parkway	0%											
6	Parkway-Dawn	18%		20%		21%		22%		20%		18%	
7	Parkway-Niagara	1%											
8	Parkway-East Hereford	0%	0%	1%	0%	0%	0%						
9	Dawn-East Hereford		1%		1%		0%						
10	Vector-Dawn	51%		50%		75%		74%		77%		80%	
11	Dawn-Court Vector		22%		19%		45%		44%		55%		54%
12	Dawn-North Bay JT		0%										
13	NIT-Empress		18%		17%		28%		30%		33%		27%
14	Parkway-North Bay JT		0%										
15	Parkway-Union NDA							0%		0%		0%	
16	ACE - US CA IC (Vector)								10%		11%		9%
17	Parkway-TCPL											0%	
18	Parkway-Union WDA												
19	Parkway-Napierville												
20	Union SSMDA-Parkway												
21	Dawn-Union EDA												
		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

2024 Percentage of Gas Exchanged by Path

		July		August		September		October		November		December	
Line No	Path	Union Rate Zones (m)	EGD Rate Zone (n)	Union Rate Zones (o)	EGD Rate Zone (p)	Union Rate Zones (q)	EGD Rate Zone (r)	Union Rate Zones (s)	EGD Rate Zone (t)	Union Rate Zones (u)	EGD Rate Zone (v)	Union Rate Zones (w)	EGD Rate Zone (x)
1	Parkway-Waddington		14%		6%		10%		20%	50%	12%	59%	24%
2	Dawn-Waddington		12%		5%		6%		9%		46%		44%
3	Parkway-Union EDA			0%							2%		0%
4	Parkway-Union SSMDA	2%		3%		5%		9%		7%		0%	
5	Union EDA-Parkway												
6	Parkway-Dawn	18%		19%		26%		55%		41%		36%	
7	Parkway-Niagara												
8	Parkway-East Hereford										1%		1%
9	Dawn-East Hereford										1%		1%
10	Vector-Dawn	80%		78%		69%		36%		1%		1%	
11	Dawn-Court Vector		44%		51%		39%		13%		1%		0%
12	Dawn-North Bay JT												3%
13	NIT-Empress		24%		28%		33%		43%		35%		24%
14	Parkway-North Bay JT												2%
15	Parkway-Union NDA			0%									
16	ACE - US CA IC (Vector)		6%		10%		12%		15%				
17	Parkway-TCPL												
18	Parkway-Union WDA			0%								0%	
19	Parkway-Napierville									0%		4%	
20	Union SSMDA-Parkway											0%	
21	Dawn-Union EDA										3%		0%
		100%	100%	101%	100%	100%	100%	100%	100%	99%	100%	100%	100%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 1, Table 1, QRAM's Exhibit C, Tab 1, Schedule 1
& EB-2024-0125 Exhibit I.FRPO-2,3

Preamble:

EGI's IRR FRPO-3 stated: *In 2023, the Company was able to generate more transactional services optimization revenue using EGD Rate Zone assets compared to Union Rate Zones assets as:*

- *Exchanges transacted using EGD Rate Zone assets are higher on TCPL's Priority of Service; and*
- *The EGD Rate Zone holds more assets that enable firm transportation to and diversion of transportation volumes to Waddington.*

Question(s):

Drawing evidence from each QRAM during the 2022-2024 period, please provide 4 tables that provide a quarterly comparison for each year that evidences the transportation costs from lines 10.1 to 10.15 and the total in line 10 for EGD.

a) Please provide the comparable table for the UGL assets.

Response:

Please see Attachment 1 for the EGD rate zone forecasted transportation costs for each QRAM in 2024, and Attachment 2 for the Union rate zones forecasted transportation costs for each QRAM in 2024.

This application is about 2024 financial results and associated variance and deferral account balances. It does not appear to Enbridge Gas that the information requested for 2022 and 2023 is relevant and as such, Enbridge Gas declines to provide the requested data for 2022 and 2023.

Forecasted Transportation Costs in 2024 - EGD Rate Zone

Line No	Particulars	Jan 2024 QRAM (1)	Apr 2024 QRAM (2)	Jul 2024 QRAM (3)	Oct 2024 QRAM (4)
1	TCPL Long Haul	89,632.7	89,632.7	89,632.7	89,632.7
	TCPL Short Haul				
2	From Dawn	46,592.7	46,592.7	46,592.7	46,592.7
3	From Parkway	51,882.1	51,882.1	51,882.1	51,882.1
4	From Niagara	17,601.9	17,601.9	17,601.9	17,601.9
5	Nova	8,748.8	9,688.5	9,688.5	9,688.5
7	Vector	14,609.6	14,135.1	14,137.2	13,930.2
8	NEXUS	47,854.5	47,172.1	47,718.2	47,563.3
	Total Transportation Costs	276,922.2	276,705.1	277,253.3	276,891.4

Notes:
(1) Jan 2024 QRAM, EB-2023-0330
(2) Apr 2024 QRAM, EB-2024-0093
(3) Jul 2024 QRAM, EB-2024-0166
(4) Oct 2024 QRAM, EB-2024-0245

Forecasted Transportation Costs in 2024 - Union Rate Zones

Line No.	Particulars	Jan 2024 QRAM (1)	Apr 2024 QRAM (2)	Jul 2024 QRAM (3)	Oct 2024 QRAM (4)
1	TCPL Long Haul	19,441.5	19,441.5	19,441.5	19,441.5
	TCPL Short Haul				
2	From Dawn	762.4	762.4	762.4	762.4
3	From Parkway	44,313.0	44,313.0	44,313.0	44,313.0
4	From Niagara	1,263.0	1,263.0	1,263.0	1,263.0
5	Kirkwall to Union CDA	5,385.1	5,385.1	5,385.1	5,385.1
6	Great Lakes	5,706.4	5,665.1	5,697.3	5,688.3
7	Centra Pipelines	1,466.0	1,462.1	1,462.9	1,505.9
8	Panhandle	14,489.4	14,089.3	14,252.1	14,222.9
9	Vector	8,266.7	8,129.5	8,242.8	8,216.2
10	NEXUS	64,714.7	63,790.9	64,529.2	64,319.9
	Total Transportation Costs	165,808.2	164,301.8	165,349.4	165,118.1

Notes:

(1) Jan 2024 QRAM, EB-2023-0330
(2) Apr 2024 QRAM, EB-2024-0093
(3) Jul 2024 QRAM, EB-2024-0166
(4) Oct 2024 QRAM, EB-2024-0245

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 1, Table 1, QRAM's Exhibit C, Tab 1, Schedule 1
& EB-2024-0125 Exhibit I.FRPO-2,3

Preamble:

EGI's IRR FRPO-3 stated: *In 2023, the Company was able to generate more transactional services optimization revenue using EGD Rate Zone assets compared to Union Rate Zones assets as:*

- *Exchanges transacted using EGD Rate Zone assets are higher on TCPL's Priority of Service; and*
- *The EGD Rate Zone holds more assets that enable firm transportation to and diversion of transportation volumes to Waddington.*

Question(s):

Please provide an explanation and the calculation of net revenue for January 2024 for both EGD and UGL assets.

Response:

Please see Table 1 for the January 2024 net revenue for EGD and Union rate zones which consists of the upstream revenue (line 1) offset by the incremental expenses tied to the exchange, such as tolls, fuel or commodity charges, and diversion-related costs (line 2).

Table 1

January 2024 Net Revenue from Upstream Transportation Optimization

Line No.	Particulars ($ millions)	EGD Rate Zone	Union Rate Zones
		(a)	(b)
1	Upstream Revenue	11.4	1.5
2	Cost	(0.2)	(0.3)
3	Net Revenue	11.2	1.2

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 1, Table 1, QRAM's Exhibit C, Tab 1, Schedule 1
& EB-2024-0125 Exhibit I.FRPO-2,3

Preamble:

EGI's IRR FRPO-3 stated: *In 2023, the Company was able to generate more transactional services optimization revenue using EGD Rate Zone assets compared to Union Rate Zones assets as:*

- *Exchanges transacted using EGD Rate Zone assets are higher on TCPL's Priority of Service; and*
- *The EGD Rate Zone holds more assets that enable firm transportation to and diversion of transportation volumes to Waddington.*

Question(s):

Please identify whether are any asset or contract costs deducted from optimization revenue to determine net revenue? If so, please provide the rationale for its deduction.

Response:

Please see response at Exhibit I.FRPO-4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 1, Table 1, QRAM's Exhibit C, Tab 1, Schedule 1
& EB-2024-0125 Exhibit I.FRPO-2,3

Preamble:

EGI's IRR FRPO-3 stated: *In 2023, the Company was able to generate more transactional services optimization revenue using EGD Rate Zone assets compared to Union Rate Zones assets as:*

- *Exchanges transacted using EGD Rate Zone assets are higher on TCPL's Priority of Service; and*
- *The EGD Rate Zone holds more assets that enable firm transportation to and diversion of transportation volumes to Waddington.*

Question(s):

For each month during the 2022-2024 period for Union Gas rate zones, please provide specific transportation paths that resulted in UDC by providing the amount of capacity and the cost,

a) Please show how those costs were removed from the PGVA to eliminate the risk of double counting.

Response:

Please see Attachment 1 for actual monthly UDC volumes and costs by transportation path for each of the Union rate zones from 2022 to 2024.

a) For each applicable month, the net UDC costs[1] incurred are removed from (credited to) the Gas Cost Deferral Accounts, where the transportation demand

[1] Net UDC costs incurred are derived from the "Actual UDC Costs Incurred ($000s)" set out in Exhibit E, Tab 1, Schedule 1, Table 1, Line No. 2, less "Actual Released Capacity Revenue ($000s)" set out in Line No. 3, which refers to revenues generated from capacity volumes released by the Company to the market.

charges were initially recorded, and reallocated (debited) to the UDC Variance Account. This ensures the costs are accurately assigned to the appropriate deferral account and eliminates the risk of double counting.

Union North East 3-Year Unutilized Capacity & Net Cost

Line No.	Month	Path/Hub	Receipt Point	Delivery Point	UDC Volume Incurred (TJ)	Actual UDC Cost Incurred ($000s)
		(a)	(b)	(c)	(d)	(e)
	2022					
1	Apr-22	NEXUS	Clarington	St. Clair	32	39
2	May-22	NEXUS	Clarington	St. Clair	17	22
3	May-22	NEXUS	Kensington	St. Clair	5	5
4	Jun-22	NEXUS	Clarington	St. Clair	23	29
5	Jun-22	NEXUS	Kensington	St. Clair	23	25
6	Jul-22	Dawn	Parkway	Union EDA	244	91
7	Jul-22	NEXUS	Clarington	St. Clair	75	92
8	Jul-22	NEXUS	Kensington	St. Clair	4	4
9	Aug-22	Dawn	Parkway	Union EDA	579	176
10	Sep-22	Dawn	Parkway	Union EDA	760	232
11	Oct-22	NEXUS	Clarington	St. Clair	140	-
12	Oct-22	NEXUS	Kensington	St. Clair	28	-
13	2022 Total				1,931	715
	2023					
14	Mar-23	Dawn	Parkway	Union EDA	948	288
15	Apr-23	Dawn	Parkway	Union EDA	1,038	326
16	Apr-23	NEXUS	Clarington	St.Clair	19	27
17	Apr-23	Dawn	Parkway	Union EDA	173	55
18	May-23	NEXUS	Clarington	St.Clair	52	73
19	May-23	NEXUS	Kensington	St.Clair	150	163
20	May-23	Dawn	Parkway	Union EDA	144	44
21	Jun-23	Dawn	Parkway	Union EDA	120	38
22	Jun-23	NEXUS	Clarington	St.Clair	36	50
23	Jun-23	NEXUS	Kensington	St.Clair	98	108
24	Jul-23	Dawn	Parkway	Union EDA	173	53
25	Aug-23	Dawn	Parkway	Union EDA	141	43
26	Sep-23	NEXUS	Clarington	St.Clair	14	21
27	Sep-23	NEXUS	Kensington	St.Clair	35	40
28	Sep-23	Dawn	Parkway	Union EDA	150	47
29	Oct-23	Empress	Empress	Union NCDA	31	32
30	Oct-23	Empress	Empress	Union NDA	65	52
31	Oct-23	Dawn	Parkway	Union EDA	1,073	326
32	Oct-23	NEXUS	Clarington	St.Clair	12	16
33	Oct-23	Dawn	Parkway	Union EDA	190	58
34	Nov-23	Dawn	Parkway	Union EDA	1,161	365
35	Nov-23	Dawn	Parkway	Union EDA	31	-
36	Nov-23	NEXUS	Clarington	St.Clair	15	21
37	Nov-23	NEXUS	Kensington	St.Clair	6	7
38	Dec-23	Dawn	Parkway	Union EDA	536	163
39	Dec-23	Dawn	Parkway	Union EDA	38	-
40	Dec-23	NEXUS	Clarington	St.Clair	1	1
41	2023 Total				6,448	2,416
	2024					
42	Jan-24	Dawn	Parkway	Union EDA	9	2
43	Feb-24	Dawn	Parkway	Union EDA	44	-
44	Mar-24	Dawn	Parkway	Union EDA	1,189	341
45	Mar-24	NEXUS	Clarington	St.Clair	34	47
46	Mar-24	NEXUS	Kensington	St.Clair	43	47
47	Apr-24	Dawn	Parkway	Union EDA	1,151	341
48	Apr-24	NEXUS	Clarington	St Clair	322	467
49	Apr-24	NEXUS	Kensington	St Clair	351	400
50	May-24	Dawn	Parkway	Union EDA	1,214	348
51	May-24	NEXUS	Clarington	St Clair	58	81
52	May-24	NEXUS	Kensington	St Clair	41	45
53	Jun-24	NEXUS	Clarington	St Clair	0	1
54	Jun-24	NEXUS	Kensington	St Clair	0	1
55	Jun-24	Dawn	Parkway	Union EDA	1,200	355
56	Jul-24	NEXUS	Clarington	St Clair	0	0
57	Jul-24	Dawn	Parkway	Union EDA	1,238	355
58	Aug-24	Dawn	Parkway	Union EDA	1,227	351
59	Aug-24	NEXUS	Clarington	St Clair	3	4
60	Sep-24	Dawn	Parkway	Union EDA	1,205	357
61	Sep-24	NEXUS	Clarington	St Clair	10	14
62	Sep-24	NEXUS	Kensington	St Clair	12	14
63	Oct-24	Dawn	Parkway	Union EDA	1,224	351
64	Oct-24	NEXUS	Clarington	St Clair	15	21
65	Nov-24	Dawn	Parkway	Union EDA	1,140	338
66	Nov-24	Dawn	Parkway	Union EDA	51	-
67	Dec-24	Dawn	Parkway	Union EDA	1,177	337
68	Dec-24	NEXUS	Kensington	St.Clair	0	0
69	2024 Total				12,959	4,616

Union North West 3-Year Unutilized Capacity & Net Cost

Line No.	Month	Path/Hub	Receipt Point	Delivery Point	UDC Volume Incurred (TJ)	Actual UDC Cost Incurred ($000s)
		(a)	(b)	(c)	(d)	(e)
	2022					
1	May-22	TCPL	Empress	Centrat MDA	173	78
2	May-22	TCPL	Empress	Union WDA	481	305
3	May-22	TCPL	Empress	Union SSMDA	62	55
4	Jun-22	TCPL	Empress	Centrat MDA	167	78
5	Jun-22	TCPL	Empress	Union WDA	765	501
6	Jun-22	TCPL	Empress	Union WDA	150	98
7	Jun-22	TCPL	Empress	Union SSMDA	90	82
8	Jun-22	Empress	Empress	Union WDA	101	66
9	Jun-22	Empress	Empress	Union SSMDA	52	47
10	Jul-22	TCPL	Empress	Centrat MDA	78	35
11	Jul-22	TCPL	Empress	Centrat MDA	95	43
12	Jul-22	TCPL	Empress	Union WDA	300	190
13	Jul-22	TCPL	Empress	Union WDA	388	246
14	Jul-22	TCPL	Empress	Union WDA	459	291
15	Jul-22	TCPL	Empress	Union SSMDA	78	68
16	Jul-22	TCPL	Empress	Union SSMDA	109	96
17	Jul-22	Empress	Empress	Union SSMDA	5	5
18	Aug-22	TCPL	Empress	Centrat MDA	173	78
19	Aug-22	TCPL	Empress	Union WDA	1,085	688
20	Aug-22	TCPL	Empress	Union SSMDA	186	164
21	Aug-22	Empress	Empress	Union SSMDA	0	0
22	Sep-22	TCPL	Empress	Centrat MDA	75	35
23	Sep-22	TCPL	Empress	Centrat MDA	92	43
24	Sep-22	TCPL	Empress	Union WDA	75	49
25	Sep-22	TCPL	Empress	Union WDA	615	403
26	Sep-22	TCPL	Empress	Union SSMDA	120	109
27	2022 Total				5,972	3,853
	2023					
28	Apr-23	Empress	Empress	Union WDA	90	48
29	Apr-23	Empress	Empress	Union MDA	167	63
30	May-23	Empress	Empress	Centrat MDA	8	3
31	May-23	Empress	Empress	Union WDA	124	64
32	May-23	Empress	Empress	Centrat MDA	164	60
33	May-23	Empress	Empress	Union WDA	155	79
34	May-23	Empress	Empress	Union WDA	310	159
35	May-23	Empress	Empress	Union SSMDA	124	88
36	Jun-23	Empress	Empress	Union WDA	733	388
37	Jun-23	Empress	Empress	Union WDA	150	79
38	Jun-23	Empress	Empress	Centrat MDA	167	63
39	Jul-23	Empress	Empress	Centrat MDA	173	63
40	Jul-23	Empress	Empress	Union WDA	105	54
41	Jul-23	Empress	Empress	Union WDA	307	158
42	Jul-23	Empress	Empress	Union WDA	173	88
43	Jul-23	Empress	Empress	Union WDA	327	168
44	Aug-23	Empress	Empress	Centrat MDA	173	63
45	Sep-23	Empress	Empress	Union WDA	9	4
46	Oct-23	Empress	Empress	Centrat MDA	173	63
47	Oct-23	Empress	Empress	Union WDA	155	79
48	Oct-23	Empress	Empress	Union WDA	248	127
49	Nov-23	Empress	Empress	Union WDA	150	79
50	Nov-23	Empress	Empress	Centrat MDA	167	63
51	2023 Total				4,351	2,105
	2024					
52	Mar-24	Empress	Empress	Centrat MDA	173	57
53	Apr-24	Empress	Empress	Union WDA	120	58
54	Apr-24	Empress	Empress	Centrat MDA	167	57
55	May-24	Empress	Empress	Centrat MDA	173	57
56	May-24	Empress	Empress	Union WDA	558	260
57	May-24	Empress	Empress	Union SSMDA	124	80
58	May-24	Empress	Empress	Union SSMDA	1	1
59	Jun-24	Empress	Empress	Centrat MDA	167	57
60	Jun-24	Empress	Empress	Union WDA	150	72
61	Jun-24	Empress	Empress	Union WDA	935	450
62	Jun-24	Empress	Empress	Union SSMDA	150	100
63	Jun-24	Empress	Empress	Union SSMDA	60	40
64	Jun-24	Empress	Empress	Union SSMDA	3	50
65	Jul-24	Empress	Empress	Centrat MDA	173	57
66	Jul-24	Empress	Empress	Union WDA	155	72
67	Jul-24	Empress	Empress	Union WDA	1,152	537
68	Jul-24	Empress	Empress	Union SSMDA	155	100
69	Jul-24	Empress	Empress	Union SSMDA	62	40
70	Jul-24	Empress	Empress	Union SSMDA	3	2
71	Aug-24	Empress	Empress	Centrat MDA	173	57
72	Aug-24	Empress	Empress	Union WDA	155	72
73	Aug-24	Empress	Empress	Union WDA	1,152	537
74	Aug-24	Empress	Empress	Union SSMDA	155	100
75	Aug-24	Empress	Empress	Union SSMDA	62	40
76	Sep-24	Empress	Empress	Centrat MDA	167	57
77	Sep-24	Empress	Empress	Union WDA	150	72
78	Sep-24	Empress	Empress	Union WDA	695	334
79	Sep-24	Empress	Empress	Union SSMDA	150	100
80	Oct-24	Empress	Empress	Centrat MDA	173	57
81	Oct-24	Empress	Empress	Union WDA	341	159
85	2024 Total				7,849	3,735

Union South 3-Year Unutilized Capacity & Net Cost

Line No.	Time	Path/Hub	Receipt Point	Delivery Point	UDC Volume Incurred (TJ)	Actual UDC Cost Incurred ($000s)
		(a)	(b)	(c)	(d)	(e)
	2022					
1	Apr-22	TCPL	Empress	Dawn	14	12
2	Apr-22	NEXUS	Clarington	St. Clair	40	49
3	May-22	NEXUS	Clarington	St. Clair	35	43
4	May-22	NEXUS	Kensington	St. Clair	9	10
5	Jun-22	PEPL	PEPL	Ojibway	1,038	867
6	Jun-22	NEXUS	Clarington	St. Clair	47	59
7	Jun-22	NEXUS	Kensington	St. Clair	47	50
8	Jul-22	Vector	Vector	Dawn	654	142
9	Jul-22	Dawn	Dawn	Dawn	780	-
10	Jul-22	PEPL	PEPL	Ojibway	1,073	875
11	Jul-22	NEXUS	Clarington	St. Clair	150	183
12	Jul-22	NEXUS	Kensington	St. Clair	8	8
13	Aug-22	Vector	Vector	Dawn	654	142
14	Aug-22	Dawn	Dawn	Dawn	1,565	-
15	Sep-22	Vector	Vector	Dawn	633	130
16	Sep-22	Dawn	Dawn	Dawn	1,729	-
17	Oct-22	NEXUS	Clarington	St. Clair	280	-
18	Oct-22	NEXUS	Kensington	St. Clair	56	-
19	2022 Total				8,813	2,569
	2023					
20	Mar-23	Dawn	Dawn	Dawn	1,217	-
21	Apr-23	Dawn	Dawn	Dawn	2,452	-
22	Apr-23	PEPL	PEPL	Ojibway	696	612
23	Apr-23	NEXUS	Clarington	St.Clair	37	53
24	May-23	Dawn	Dawn	Dawn	1,145	-
25	May-23	PEPL	PEPL	Ojibway	720	614
26	May-23	NEXUS	Clarington	St.Clair	105	146
27	May-23	NEXUS	Kensington	St.Clair	300	326
28	May-23	Vector	Vector	Dawn	318	66
29	Jun-23	Vector	Vector	Dawn	760	158
30	Jun-23	PEPL	PEPL	Ojibway	696	603
31	Jun-23	NEXUS	Clarington	St.Clair	71	100
32	Jun-23	NEXUS	Kensington	St.Clair	196	216
33	Jul-23	Vector	Vector	Dawn	818	166
34	Jul-23	Vector	Vector	Dawn	654	129
35	Jul-23	PEPL	PEPL	Ojibway	720	599
36	Jul-23	Dawn	Dawn	Dawn	2,715	-
37	Sep-23	Empress	Empress	Union CDA	1	1
38	Sep-23	NEXUS	Clarington	St.Clair	29	42
39	Sep-23	NEXUS	Kensington	St.Clair	71	80
40	Sep-23	Dawn	Dawn	Dawn	1,500	-
41	Oct-23	PEPL	PEPL	Ojibway	1,864	1,082
42	Oct-23	Vector	Vector	Dawn	818	172
43	Oct-23	Vector	Vector	Dawn	654	134
44	Oct-23	NEXUS	Clarington	St.Clair	23	33
45	Nov-23	PEPL	PEPL	Ojibway	855	512
46	Nov-23	Dawn	Dawn	Dawn	2,146	-
47	Nov-23	NEXUS	Clarington	St.Clair	7	11
48	Nov-23	NEXUS	Kensington	St.Clair	3	4
49	Dec-23	Dawn	Dawn	Dawn	1,759	-
50	Dec-23	NEXUS	Clarington	St.Clair	1	2
51	2023 Total				23,348	5,857
	2024					
52	Jan-24	PEPL	PEPL	Ojibway	1	1
53	Mar-24	Dawn	Dawn	Dawn	2,217	-
54	Mar-24	NEXUS	Clarington	St.Clair	67	94
55	Mar-24	NEXUS	Kensington	St.Clair	87	95
56	Apr-24	Dawn	Dawn	Dawn	3,900	-
57	Apr-24	NEXUS	Clarington	St Clair	643	934
58	Apr-24	NEXUS	Kensington	St Clair	703	799
59	May-24	Dawn	Dawn	Dawn	4,030	-
60	May-24	PEPL	PEPL	Ojibway	1,864	1,079
61	May-24	NEXUS	Clarington	St Clair	115	162
62	May-24	NEXUS	Kensington	St Clair	81	89
63	May-24	Vector	Vector	Dawn	0	0
64	May-24	Niagara	Niagara Falls	Kirkwall	0	0
65	May-24	Empress	Empress	Dawn	80	57
66	Jun-24	Dawn	Dawn	Dawn	2,400	-
67	Jun-24	NEXUS	Clarington	St Clair	1	1
68	Jun-24	NEXUS	Kensington	St Clair	1	1
69	Jun-24	Empress	Empress	Dawn	260	192
70	Jun-24	Vector	Vector	Dawn	633	137
71	Jun-24	Vector	Vector	Dawn	950	205
72	Jul-24	Vector	Vector	Dawn	654	137
73	Jul-24	Vector	Vector	Dawn	981	205
74	Jul-24	PEPL	PEPL	Ojibway	941	546
75	Jul-24	NEXUS	Clarington	St Clair	0	1
76	Jul-24	Empress	Empress	Emerson 2	225	80
77	Jul-24	Vector	Vector	Dawn	421	88
78	Aug-24	Vector	Vector	Dawn	654	136
79	Aug-24	Vector	Vector	Dawn	981	204
80	Aug-24	Empress	Empress	Emerson 2	180	64
81	Aug-24	NEXUS	Clarington	St Clair	5	8
82	Aug-24	Dawn	Dawn	Dawn	946	-
83	Sep-24	Vector	Vector	Dawn	633	135
84	Sep-24	Vector	Vector	Dawn	317	68
85	Sep-24	Vector	Vector	Dawn	633	135
86	Sep-24	Empress	Empress	Emerson 2	16	6
87	Sep-24	NEXUS	Clarington	St Clair	19	27
88	Sep-24	NEXUS	Kensington	St Clair	25	28
89	Sep-24	Dawn	Dawn	Dawn	1,000	-
90	Sep-24	Empress	Empress	Emerson 2	135	50
91	Oct-24	Vector	Vector	Dawn	654	137
92	Oct-24	Vector	Vector	Dawn	327	69
93	Oct-24	Vector	Vector	Dawn	654	137
94	Oct-24	Dawn	Dawn	Dawn	2,030	-
95	Oct-24	Empress	Empress	Emerson 2	153	54
96	Oct-24	Empress	Empress	Emerson 2	26	9
97	Oct-24	NEXUS	Clarington	St Clair	30	42
98	Nov-24	Niagara	Niagara Falls	Kirkwall	5	1
99	Nov-24	Empress	Empress	Emerson 2	8	3
100	Nov-24	Empress	Empress	Emerson 2	96	35
101	Nov-24	Dawn	Dawn	Dawn	50	-
102	Dec-24	Dawn	Dawn	Dawn	50	-
103	Dec-24	Empress	Empress	Emerson 2	10	3
104	Dec-24	NEXUS	Kensington	St.Clair	0	0
105	2024 Total				30,894	6,257

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 2

Preamble:

EGI evidence states: *The balance of $0.073 million represents the difference between the TransCanada capacity costs incurred by Enbridge Gas of $2.006 million and the revenues collected from customers of $1.933 million. The net variance is driven by a reduction of 480 GJ per day of contracted quantity by Union North T-service customers.*

Question(s):

Has EGI optimized this under-utilized transport?

a) If so, please explain how the capacity was optimized
    i. where does the incremental revenue accrue?
b) If not, what was it used for?
    i. If not used for anything, why did EGI not sell the contract assignment?

Response:

a) No, Enbridge Gas has not optimized the 480 GJ of excess capacity.

b) The excess capacity is for transport to the Union NDA and is for a very small quantity. It is held for and re-marketed to customers in the Union North, but no interest in the capacity was expressed by customers or their marketers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3

Preamble:

EGI evidence states: *2024 marks the first year the Union Rates Zones adopted the harmonized methodology consistent with the LEGD Rate Zone. Consequently, 2024 Union Rate Zones UFG volumes were affected by the adjustments for both December 2023 and December 2024 unbilled and no-bill estimates. The impact of the December 2023 unbilled and no-bill estimates (as was the previous practice) on 2024's UFGVVA was an increase in UFG recorded in the variance account of approximately 21,049 103m3. The impact of the December 2024 unbilled and no-bill estimates was an increase of 63,948 103m3. In the absence of the harmonized methodology, the adjustment of 63,948 103m3 relating to December 2024 estimates would have rolled over into 2025 and would not have impacted the 2024 UFGVVA balance.*

Question(s):

Please explain precisely what are:

a) No bill adjustments
b) Unbilled adjustments

Response:

a) No Bill adjustments - "No Bills" refers to the scenario where a bill has not been issued to a customer in a given accounting period. In these instances, Enbridge Gas' financial practice is to record an estimate of gas volumes delivered but not yet billed, which follows a process very similar to the "cycle-billed" unbilled estimation process. The No Bills estimate is calculated at the rate class level and recorded within the financial accounting system. This estimate considers factors such as billing cycles, number of customers, number of billing periods which have not been billed, average use per HDD, actual HDDs, and demand coefficients. The No Bills Consumption estimate that is recorded in each reporting period in the financial accounting system is reversed in the following reporting period and replaced by actual billed Consumption. To the extent that the estimate of the Consumption recorded in the accounting system differs from the actual billed Consumption, a volumetric adjustment is completed in the financial accounting system and recorded to reflect the difference.

b) Unbilled adjustments - To align the reporting of monthly customer Consumption with calendar month reporting periods for accounting purposes, it is necessary to record an estimate of gas delivered but not yet billed at the end of every monthly reporting period. This estimate is recorded in the financial accounting system and is calculated at the rate class level. This estimate considers factors such as number of customers per billing cycle, number of days for each cycle which have not been billed, average use per HDD, actual HDDs, and demand coefficients. The unbilled Consumption estimate that is recorded in each reporting period in the accounting system is reversed in the following reporting period and replaced by actual billed Consumption. To the extent that the estimate of the unbilled Consumption differs from the actual billed Consumption, a volumetric adjustment is performed and recorded to reflect the difference.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3

Preamble:

EGI evidence states: 2024 marks the first year the Union Rates Zones adopted the harmonized methodology consistent with the LEGD Rate Zone. Consequently, 2024 Union Rate Zones UFG volumes were affected by the adjustments for both December 2023 and December 2024 unbilled and no-bill estimates. The impact of the December 2023 unbilled and no-bill estimates (as was the previous practice) on 2024's UFGVVA was an increase in UFG recorded in the variance account of approximately 21,049 103m3. The impact of the December 2024 unbilled and no-bill estimates was an increase of 63,948 103m3. In the absence of the harmonized methodology, the adjustment of 63,948 103m3 relating to December 2024 estimates would have rolled over into 2025 and would not have impacted the 2024 UFGVVA balance.

Question(s):

Please explain if any of the volumes associated with these adjustments could result in revenue generated in 2025.

Response:

No, the volumes associated with the adjustments described do not result in a change to the method of recognizing revenue or the time period in which it is recognized.

Enbridge Gas continues to recognize revenue consistent with historical practice, irrespective of the harmonization of the Unaccounted for Gas Volume Variance Account (UFGVVA) methodology. The recognition of revenue in a given time period is based on the sum of billed consumption volumes and unbilled and no-bill consumption volumes. The estimation of unbilled and no-bill consumption volumes is necessary to ensure that gas that has been consumed but not yet billed is properly reflected in the appropriate accounting period that it pertains to. In the following accounting period, a volumetric adjustment is performed to record the difference between the estimated unbilled and no-bill consumption and the actual billed consumption.

The harmonized methodology for the determination of the UFGVVA did, however, impact the fiscal period in which that adjustment was recorded, for the purposes of the determination of the UFGVVA. Prior to 2024, in the Union rate zone, the adjustment for the December unbilled and no-bill estimate variance would have been recorded in the UFG variance account in the following fiscal period. Upon harmonization, the adjustment for the unbilled and no-bill estimate is recorded in UFGVVA for the fiscal year that the consumption pertains to. The adjustments are made through a mechanistic methodology without bias, which are subject to internal and external auditor review. The harmonization helps to ensure closer alignment between Sendout volumes and Consumption volumes, to minimize the UFG volatility that can result from estimation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3

Preamble:

EGI evidence states: *2024 marks the first year the Union Rates Zones adopted the harmonized methodology consistent with the LEGD Rate Zone. Consequently, 2024 Union Rate Zones UFG volumes were affected by the adjustments for both December 2023 and December 2024 unbilled and no-bill estimates. The impact of the December 2023 unbilled and no-bill estimates (as was the previous practice) on 2024's UFGVVA was an increase in UFG recorded in the variance account of approximately 21,049 103m3. The impact of the December 2024 unbilled and no-bill estimates was an increase of 63,948 103m3. In the absence of the harmonized methodology, the adjustment of 63,948 103m3 relating to December 2024 estimates would have rolled over into 2025 and would not have impacted the 2024 UFGVVA balance.*

Question(s):

Please explain how a no bill and unbilled adjustments result in incremental volumes of UFG.

Response:

December 2024 unbilled and no-bill estimates relative to actual consumption had an impact on reported UFG in 2024 of 63,948 10^3m^3. Under the previous methodology this impact would have been reported in 2025. Unbilled and no-billed estimates do not create incremental UFG, but the change in methodology resulted in a change to when that impact was reported.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 6

Question(s):

Please confirm or clarify that the extension of the PDO to EGD CDA customers would be implemented with Phase 3 rate changes in 2027.

Response:

Confirmed. Enbridge Gas is proposing to expand the PDO and PDCI offering to customers located in the EGD rate zone who are contractually obligated to deliver gas to the Enbridge CDA as part of the Settlement Proposal for the 2024 Rebasing Phase 3 proceeding.[1] If approved by the OEB, Enbridge Gas proposes to implement this change with harmonized rates in 2027.

[1] EB-2025-0064, Settlement Proposal, Exhibit N, Tab 1, Schedule 1, January 21, 2026, p.33.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 13

Preamble:

Amongst the costs identified in Table 1 is Professional Dues

Question(s):

Please describe why this category is a significant cost.

a) Please explain why this cost is incremental to the utilities base O&M budget.

Response:

"Professional Dues" were included in the description to give a complete picture of all types of costs within this Admin bucket. However, the professional dues costs themselves are not significant in dollar amount, totaling only $3,644 across the DIMP and EDIMP Admin cost categories.

a) Please see response at Exhibit I.CCC-5 part b) for a detailed breakdown of administrative costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 13

Preamble:

EGI evidence states: *Investigations and assessments accounted for $0.363 million of the variance, which has driven primarily by the incremental work required for an Aldyl "A" polyethylene (PE) pipe survey, as a result of some recent industry events. The survey was initiated on approximately 200 gas mains to verify the field installation of Aldyl "A" PE pipeline that was not recorded during installation in the 1970's. The survey provided Enbridge Gas with more certainty on the inventory of Aldyl "A" PE pipelines within the network and was pursued following recent safety-related incidents in the U.S. involving Aldyl "A" PE pipelines.*

Question(s):

Please provide a summary of the issues observed in the U.S., including references to the sources of information on these risks and how the utilities are mitigating the risks.

Response:

Utilities generally use additional leak surveys above minimum requirements and/or replacement programs to mitigate the Aldyl "A" risk to the distribution system. Both approaches involve risk-informed decision-making, applying factors in risk modeling to prioritize assets with the highest likelihood and consequence of failure based on environmental operating conditions. Table 1 below summarizes the recent safety-related incidents in the U.S. involving Aldyl "A" PE pipelines.

Table 1
Recent Safety-Related Incidents in the U.S. Involving Aldyl "A" PE Pipelines

Line No.	Incident Location	Year of Accident	Number of Fatalities	Number of Injured	Property damage	Summary of Incident Cause
1	West Reading, Pennsylvania[1]	2023	7	10	Explosion destroyed commercial workplace/buildings	Steam line near Aldyl "A" service tee caused accelerated degradation of tee
2	South Jordan, Utah[2]	2024	1	0	Destroyed house and damage to neighbouring houses	Cracked Aldyl "A" pipe due to rock impingement

[1] National Transportation Safety Board, "UGI Corporation Natural Gas-Fueled Explosion and Fire," Washington, 2023.
[2] National Transportation Safety Board, "South Jordan, Utah Group Chair's Factual Report," Washington, 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 13

Question(s):

Please provide the number of isolated steel services in casings that have been confirmed to have leakage.

Response:

Enbridge Gas did not report any leaks on isolated steel services in casings in 2024. However, to clarify, the pipe inspections referenced in Exhibit C, Tab 2, Schedule 13, page 4, paragraph 11 involve two distinct inspection types:

i. inspections of isolated steel services and risers; and
ii. casing inspections.

The casing inspections refer specifically to assessments of casings on distribution steel gas mains, not services.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

C, Tab 2, Schedule 17, Attachment 1

Preamble:

We would like to understand the reasons why Rate 1 and Rate 6 have variances in opposite directions.

Question(s):

Please provide the forecasted and actual heating degree days.

Response:

Please see Table 1 below for the forecasted and actual heating degree days (HDD) for Rate 1 and Rate 6 which consist of the Central weather zone, the East weather zone and the West weather zone. In all three weather zones, actual HDDs resulted in lower than forecast due to warmer than expected temperatures. The Average Use Variance Account (AUVA) records the revenue impact (exclusive of gas costs) of the volumetric difference between the actual weather-normalized average use experienced during the year and the forecast average use. Subsequently, since the calculations for AUVA are done on a normalized basis, the variances due to weather are excluded.

Table 1
2024 Actual and Forecasted Heating Degree Days (HDD)

Line No.	Particulars	Actual HDD (a)	Forecast HDD (b)	Variance HDD (c = a - b)
1	Central weather zone	2,381	2,764	(383)
2	East weather zone	3,026	3,479	(453)
3	West weather zone	2,237	2,605	(368)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

C, Tab 2, Schedule 17, Attachment 1

Preamble:

We would like to understand the reasons why Rate 1 and Rate 6 have variances in opposite directions.

Question(s):

Please provide the summary calculations showing how the variances were determined.

Response:

Please see Attachment 1, Table 1 and 2 for the calculations completed at monthly level showing how the final variances were determined for Rate 1 and Rate 6.

Table 1
Calculation of the Balance in the Average Use Variance Account (AUVA)
for Rate 1
Account No. 179-333

Line No.	Particulars	Unit of Measurement	Jan-2024 (a)	Feb-2024 (b)	Mar-2024 (c)	Apr-2024 (d)	May-2024 (e)	Jun-2024 (f)	Jul-2024 (g)	Aug-2024 (h)	Sep-2024 (i)	Oct-2024 (j)	Nov-2024 (k)	Dec-2024 (l)	Total (m)
1	2024 Budget Average Use	(m^3)	432	377	322	197	87	46	46	46	46	118	247	353	2,317
2	2024 Actual Normalized Average Use	(m^3)	430	365	317	192	92	59	65	56	59	115	254	342	2,347
3	Average Use Variance (line 1 - line 2)	(m^3)	2	12	5	5	(5)	(13)	(19)	(10)	(12)	3	(8)	11	(30)
4	2024 OEB-approved average number of customers (2)	(#)	2,163,088	2,163,088	2,163,088	2,163,088	2,163,088	2,163,088	2,163,088	2,163,088	2,163,088	2,163,088	2,163,088	2,163,088	
5	Normalized Volumetric Variance (line 3 x line 4)	(10^{5}m^3)	4.1	25.6	9.9	10.3	(11.2)	(28.1)	(42.0)	(21.2)	(26.4)	5.8	(16.2)	24.4	(65.1)
6	Net Weighted Average Unit Rate	(\$/m^3)	$0.087898	$0.087898	$0.087898	$0.087548	$0.087548	$0.087548	$0.087769	$0.087769	$0.087769	$0.087690	$0.087690	$0.087690	$0.087609
7	AUVA Balance Amount (line 5 x line 6)	($ millions)	$0.4	$2.2	$0.9	$0.9	($1.0)	($2.5)	($3.7)	($1.9)	($2.3)	$0.5	($1.4)	$2.1	($5.7)
8	Interest	($ millions)	$0.0	$0.2	$0.1	$0.1	($0.1)	($0.2)	($0.3)	($0.1)	($0.2)	$0.0	($0.1)	$0.2	($0.4)
9	Total AUVA Deferral Amount (line 7 + line 8)	($ millions)	$0.4	$2.4	$0.9	$1.0	($1.1)	($2.6)	($4.0)	($2.0)	($2.5)	$0.5	($1.5)	$2.3	($6.1)

Notes:
(1) Harmonized Average Use Variance Account (AUVA) as per EB-2022-0200 Decision and Order, Section 5.5.1. Reference to 'normalized' in Table 1 implies weather normalization based on 2024 Forecast Heating Degree Days (HDD).
(2) Refers to 2024 OEB-approved annual average number of customers including adjustment for customer numbers agreed to in the 2024 Rebasing Phase 1 Settlement Agreement.
(3) Represents the volume-weighted average of OEB-approved monthly unit rates in effect.
(4) Interest is calculated on the monthly opening balance in the deferral account using the OEB-approved EB-2006-0117 interest rate methodology. Interest is calculated to July 1, 2026.
(5) (+) value reflects a debit (collection) from ratepayers and refund to Enbridge Gas which results when forecasted average use is higher than the actual normalized average.
(-) value reflects a credit (refund) to ratepayers and collectable from Enbridge Gas which results when the forecasted average use is lower than the actual normalized average use.

Table 2
Calculation of the Balance in the Average Use Variance Account (AUVA) [1]
for Rate 6
Account No. 179-333

Line No.	Particulars	Unit of Measurement	Jan-2024 (a)	Feb-2024 (b)	Mar-2024 (c)	Apr-2024 (d)	May-2024 (e)	Jun-2024 (f)	Jul-2024 (g)	Aug-2024 (h)	Sep-2024 (i)	Oct-2024 (j)	Nov-2024 (k)	Dec-2024 (l)	Total (m)
1	2024 Budget Average Use	(m^3)	4,550	4,482	3,965	2,683	1,399	887	647	639	885	1,310	2,522	3,755	27,726
2	2024 Actual Normalized Average Use	(m^3)	4,969	4,601	3,842	2,572	1,291	680	517	580	751	1,090	2,768	3,882	27,543
3	Average Use Variance (line 1 - line 2)	(m^3)	(419)	(119)	124	111	108	207	130	59	134	220	(246)	(127)	183
4	2024 OEB-approved annual average number of customers [2]	(#)	172,974	172,974	172,974	172,974	172,974	172,974	172,974	172,974	172,974	172,974	172,974	172,974	
5	Normalized Volumetric Variance (line 3 x line 4)	(10^5m^3)	(72.5)	(20.5)	21.4	19.2	18.7	35.8	22.5	10.3	23.2	38.0	(42.5)	(21.9)	31.6
6	Net Weighted Average Unit Rate [3]	($/$m^3$)	$0.062695	$0.062695	$0.062695	$0.062371	$0.062371	$0.062371	$0.062577	$0.062577	$0.062577	$0.062503	$0.062503	$0.062503	$0.061892
7	AUVA Balance Amount (line 5 x line 6)	($ millions)	($4.5)	($1.3)	$1.3	$1.2	$1.2	$2.2	$1.4	$0.6	$1.5	$2.4	($2.7)	($1.4)	$2.0
8	Interest [4]	($ millions)	($0.3)	($0.1)	$0.1	$0.1	$0.1	$0.2	$0.1	$0.0	$0.1	$0.2	($0.2)	($0.1)	$0.1
9	Total AUVA Deferral Amount [5] (line 7 + line 8)	($ millions)	($4.9)	($1.4)	$1.4	$1.3	$1.3	$2.4	$1.5	$0.7	$1.6	$2.5	($2.9)	($1.5)	$2.1

Notes:
(1) Harmonized Average Use Variance Account (AUVA) as per EB-2022-0200 Decision and Order, Section 5.5.1. Reference to 'normalized' in Table 1 implies weather normalization based on 2024 Forecast Heating Degree Days (HDD).
(2) Refers to 2024 OEB-approved annual average number of customers including adjustment for customer numbers agreed to in the 2024 Rebasing Phase 1 Settlement Agreement.
(3) Represents the volume-weighted average of OEB-approved monthly unit rates in effect.
(4) Interest is calculated on the monthly opening balance in the deferral account using the OEB-approved EB-2006-0117 interest rate methodology. Interest is calculated to July 1, 2026.
(5) (+) value reflects a debit (collection) from ratepayers and refund to Enbridge Gas which results when forecasted average use is higher than the actual normalized average.
(-) value reflects a credit (refund) to ratepayers and collectable from Enbridge Gas which results when the forecasted average use is lower than the actual normalized average use.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

C, Tab 2, Schedule 17, Attachment 1

Preamble:

We would like to understand the reasons why Rate 1 and Rate 6 have variances in opposite directions.

Question(s):

Please provide a written explanation of the factors that drove the divergence in the variances.

Response:

As in past years, actual average use can vary from forecast levels across rate classes, and these variances may occur in opposite directions. This outcome is expected, as the underlying drivers of consumption and customer behaviors differ by rate class.

The 2024 forecast average use was developed using actual data through 2021[1]. The variances of +1.3% for Rate 1 and -0.7% for Rate 6 represent relatively low forecast errors and are well within the range of variability typically observed in annual average use forecasting. Even though the variances are within the normal range of forecast error, an explanation is provided below for completeness.

Between 2006 and 2021, Rate 1 average use declined at an average annual rate of approximately 0.9%, and over the 10-year period (2012-2021), the decline averaged 0.6% per year. In contrast, actual average use in 2024 declined by only 0.2%, which is materially lower than the historical trend, and resulted in higher forecast than actual (-0.7%).

[1] 3-yr ahead forecast due to 2024 Phase 1 Rebasing Application (EB-2022-0200) instead of standard 2-yr ahead forecast in rate applications within the IRM term.

Rate 6 customers consist of apartment, commercial, and industrial consumers, whose consumption levels are more sensitive to economic conditions and production activity. The variance in Rate 6 average use is primarily attributable to a slower-than-expected post-pandemic economic recovery.

For a graphical representation for Rate 1 and Rate 6 average use trend, please refer to response at Exhibit I.PP-8, Attachment 1, Figure 1 and 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 20, p. 7

Preamble:

Site Restoration Cost Variance Account (179-337)

Question(s):

Please provide a description and the calculation of the determination of the net debit balance of $1.6 billion.

Response:

The referenced $1.6 billion was an approximation of the Company's pre-2024 site restoration cost liability, which accumulated over time through to December 31, 2023, reflected within utility accumulated depreciation. The amount is the presumed cumulative amount of site restoration costs (or negative net salvage value) recovered in rates, based on the salvage component in approved depreciation rates applied to actual gross plant values through to December 31, 2023, net of actual removal and restoration costs over the same time period.

As was noted in 2024 Rebasing Phase 2, the actual site restoration cost liability as at December 31, 2023 was $1,693 million[1].

Further evidence describing the accumulation and calculation of the site restoration cost liability can be found within the following evidentiary references:

- 2024 Rebasing Phase 1, EB-2022-0200, Exhibit I.1.8-STAFF-17 (specifically parts a), b), and d)) describes the calculation and build-up of the liability.
- 2024 Rebasing Phase 1, EB-2022-0200, Exhibit I.4.5-IGUA-13, Attachment 1 presents a 2013 – 2022 continuity schedule for the liability.

[1] EB-2024-0111, Exhibit I.4.5-ED-56 part c).

- 2024 Rebasing Phase 2, EB-2024-0111, Exhibit 4, Tab 5, Schedule 2, pages 1 to 4 describes the calculation of the annual site restoration cost liability and the accumulated balance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 20, p. 7

Preamble:

Site Restoration Cost Variance Account (179-337)

Question(s):

Please confirm that the SRC account excludes any amounts related to unamortized asset balances at the time of abandonment.

Response:

Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, p. 2, plus Attachment

Preamble:

Table 1 provides a breakdown of the 2024 S&TDA for EGD rate zone. The notes indicate values associated with 2022 and 2024. We would like to understand this determination better including what is being proposed for disposition in this proceeding and specifically what has already been cleared.

Question(s):

For each of 2022 and 2024, please provide the determination for:

a) M12 transportation
b) M16 transportation

Response:

a) Please see Attachment 1 for the derivation of balances allocated to contracts held by the EGD rate zone for M12 transportation in the Union rate zone, as it relates to the 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances [1] and the 2024 Rebasing Phase 1 proceeding[2].

b) Please see Attachment 2 for the derivation of balances allocated to contracts held by the EGD rate zone for M16 transportation in the Union rate zone, as it relates to the 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding[3] and the 2024 Rebasing Phase 1 proceeding[4].

[1] EB-2023-0092.
[2] EB-2022-0200.
[3] EB-2023-0092.
[4] EB-2022-0200

Allocation of DVA Balances to M12 Transportation

Line No.	Particulars	DVA Balance Allocation to M12 ($Millions)	Total M12 CD Volume (10^6m^3)	EGD M12 CD Volume (10^6m^3)	EGD M12 Allocation (%)	DVA Balance Allocation to EGD ($Millions)
		(a)	(b)	(c)	(d) = (c)/(b)	(e) = (a) x (d)
1	2022 ESM/DVA Disposition (1)	20.9	67.4	38.2	57%	11.9
2	2024 Rebasing DVA Disposition (2)	(23.4)	66.9	38.3	57%	(13.4)

Notes:

(1) EB-2023-0092, Exhibit F, Tab 3, Schedule 3, p.1 of 2, updated October 31, 2023.

(2) EB-2022-0200, Rate Order, Updated March15, 2024, Working Papers, Schedule 27, p.5 of 6, Line 33.

Allocation of DVA Balances to M16 Transportation

Line No.	Particulars	DVA Balance Allocation to M16 ($Millions)	Total M16 CD Volume (10^6m^3)	EGD M16 CD Volume (10^6m^3)	EGD M16 Allocation (%)	DVA Balance Allocation to EGD ($Millions)
		(a)	(b)	(c)	(d) = (c)/(b)	(e) = (a) x (d)
1	2022 ESM/DVA Disposition (1)	0.30	0.21	0.13	59%	0.17
2	2024 Rebasing DVA Disposition (2)	(0.03)	0.21	0.13	59%	(0.02)

Notes:

(1) EB-2023-0092, Exhibit F, Tab 3, Schedule 3, p.1 of 2.

(2) EB-2022-0200, Rate Order, updated March 15, 2024, Working Papers, Schedule 27, p.5 of 6, Line 35.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, p. 2, plus Attachment

Preamble:

Table 1 provides a breakdown of the 2024 S&TDA for EGD rate zone. The notes indicate values associated with 2022 and 2024. We would like to understand this determination better including what is being proposed for disposition in this proceeding and specifically what has already been cleared.

Question(s):

Please provide a specific reference to the Board approval for this timing for the reconciliation and disposition of all of these accounts.

Response:

The OEB-approved reconciliation and disposition of balances to M12 and M16 customers from the 2022 Deferral and Variance Account Disposition proceeding can be found in EB-2023-0092, Decision on Settlement Proposal and Rate Order, Rate Order, Appendix C, Schedule 4, page 4, Lines 1 and 4.

The OEB-approved reconciliation and disposition of balances to M12 and M16 customers from the 2024 Rebasing Deferral Account Clearance can be found in EB-2022-0200, Rate Order, Working Papers, Schedule 27, page 5, Lines 33 and 35, updated March 15, 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, p. 2, plus Attachment

Preamble:

Table 1 provides a breakdown of the 2024 S&TDA for EGD rate zone. The notes indicate values associated with 2022 and 2024. We would like to understand this determination better including what is being proposed for disposition in this proceeding and specifically what has already been cleared.

Question(s):

Please outline the determination of deemed transportation, load balancing and peak percentages, including references to when that approach was approved by the Board.

Response:

The OEB-approved methodology for the EGD rate zone to allocate costs between commodity, transportation, and load balancing has been in place prior to the QRAM Generic Proceeding[1]. This methodology reflects the service attributes and underlying gas supply portfolio underpinning rates in the EGD rate zone.

The current methodology and its outcomes were further reviewed and approved annually up to and including the 2018 rate case[2]. Enbridge Gas has included a proposal to harmonize this approach in the 2024 Rebasing Phase 3 application[3] which is pending OEB approval.

Under the current approved cost allocation study underpinning rates for the EGD rate zone, any price premium for gas supply purchased at other supply hubs over the Empress reference price is classified as transportation (i.e. deemed transportation costs) and, in the case of delivered supplies, also to load balancing as peaking and

[1] EB-2008-0106.
[2] EB-2017-0086.
[3] EB-2025-0064.

seasonal. In this classification, 71% is attributed as seasonal load balancing and 9% peak load balancing. The remaining 20% is deemed transportation.

The relevant cost model schedules (the classification of gas costs to commodity, annual transportation and load balancing charges) and the related written evidence can be found in the 2018 rates application.[4]

[4] EB-2017-0086, Exhibit G2, Tab 6, Schedule 2, p.1 and Exhibit G2, Tab 1, Schedule 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, p. 2, plus Attachment

Preamble:

Table 1 provides a breakdown of the 2024 S&TDA for EGD rate zone. The notes indicate values associated with 2022 and 2024. We would like to understand this determination better including what is being proposed for disposition in this proceeding and specifically what has already been cleared.

Question(s):

Please provide a description of purpose, the resulting dispositions of the determined balances and how EGI has or is proposing to recover the cost for each of:

a) Table 2
b) Table 3
c) Attachment 1

Response:

Please see the response at Exhibit I.FRPO-24.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, p. 2, plus Attachment

Preamble:

Table 1 provides a breakdown of the 2024 S&TDA for EGD rate zone. The notes indicate values associated with 2022 and 2024. We would like to understand this determination better including what is being proposed for disposition in this proceeding and specifically what has already been cleared.

Question(s):

Please explain how Table 2, Table 3 and Attachment 1 work together (or individually) to reconcile forecast deliveries and rates to determine the appropriateness of the Load Balancing Supply Purchases.

a) How do these tables demonstrate the appropriate recovery of these values.
b) For the forecasted summer deliveries that were not purchased, please explain how the forecasted costs in rates were reduced or refunded so that ratepayers are not bearing the cost of the forecast.

Response:

Table 2, Table 3, and Attachment 1 are not intended to reconcile forecast deliveries and rates with load balancing supply purchases. Enbridge Gas has provided Table 2 and supporting evidence in response to the 2024 Rebasing Phase 2 Settlement Agreement[1], where the Company committed to report annually on decisions to either procure assets or additional supply to meet load balancing requirements above 199.7 PJ of cost-based storage. Enbridge Gas has provided Table 3 and Attachment 1 to illustrate the financial recovery of load balancing costs in approved base rates and load balancing rate riders based on the approved methodology for the EGD rate zone. A harmonized approach to load balancing costs has been agreed to by parties[2] and, if

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[1] EB-2024-0111, Decision on Settlement Proposal and Interim Rate Order, November 29, 2024, p.29.
[2] EB-2025-0064, 2024 Rebasing Phase 3, Settlement Proposal, December 18, 2025.

approved, will be implemented some time in 2027. Until such time, the Company continues to follow the approved QRAM methodology for the EGD rate zone for the recovery of load balancing costs. As such, Table 2 and Attachment 1 cannot be reconciled with Table 3 as Table 2 is based on actual purchases and the 2023/24 Gas Supply Plan and Table 3 is based on the gas supply plan underpinning the 2019 Rates Application[3].

a) Table 2 provides the monthly details of the planned (2023/24 Gas Supply Plan) and actual Dawn supply purchases for the EGD rate zone in 2024 (59 PJ in Table 2, the equivalent of 1,530.5 10^6m^3 in Attachment 1, column (a)). Actual Dawn supply purchases were lower than the planned monthly purchases in 2024 due to reduced customer demand.

   Volume variances between the actual Dawn supply purchases and the forecast Dawn supply purchases to serve sales service customers in the EGD rate zone represent a gas supply commodity variance which is included in the PGVA and allocated to sales service customers.

   Attachment 1 provides the details of 1) the price variance on actual Dawn supply purchases (1,530.5 10^6m^3 in Attachment 1, the equivalent of 59 PJ in Table 2) and the allocation between the commodity cost variance and the load balancing price variance, and 2) other load balancing costs and peaking cost variances.

   For 2024, the price variance related to the actual Dawn supply purchases was recorded as a credit of $20.5 million in the PGVA, as shown in Attachment 1, column (i). Of the $20.5 million, $17.7 million (column e), was refunded to sales service gas customers in the EGD rate zone through lower gas supply commodity rates.

   The remaining $2.8 million was a load balancing price variance (column j), based on actual Dawn supplies (1,530.5 10^6m^3 in Attachment 1, the equivalent of 59 PJ in Table 2), which was refunded to both sales service and direct purchase customers through the load balancing rate riders.

   Attachment 1 also provides the details of the $0.7 million credit for load balancing cost variances (column o and column k), which was refunded to both sales service and direct purchase customers through load balancing rate riders. Load balancing cost variances are allocated to each customer class in the same manner as the allocation of load balancing costs in rates.

   Table 3 provides a summary of the total load balancing costs that are recovered in base rates from customers through load balancing charges based on the long-

[3] EB-2018-0305.

standing OEB approved QRAM methodology for the EGD rate zone. The QRAM is a mechanistic approach in which forecast commodity purchase costs are used to derive gas supply charges each quarter based on the approved forecast volumes underpinning rates. Forecast Dawn supply costs are classified between gas supply commodity costs, transportation and load balancing costs. Any price premium for gas supply purchases at Dawn over the Empress reference price are assigned to the transportation and load balancing classifications per the cost allocation methodology underpinning rates. The classification of costs included in rates for 2024 are shown in lines 5 to 9 of Table 3. Peaking supply purchases are shown in line 10 and the total amount of load balancing included in base rates are shown in line 13. The forecast load balancing costs are recovered from sales service and bundled DP customers through the load balancing charges.

As noted in evidence, there is no approved methodology to determine the classification split of actual Dawn and supply peaking supply purchases. The variance between actual and forecast gas supply purchase costs, including the Dawn supply purchases, are included in the PGVA.

b) As noted in part a), volume variances between actual and forecast Dawn supply purchases are recognized as commodity variances within the PGVA. To the extent that actual Dawn supply purchases are lower than forecast, the variance is due to a reduction in customer demand. In that case, Enbridge Gas recovers lower gas supply revenues, which is offset by lower gas supply costs due to the reduction in the Dawn supply purchases.

   Furthermore, Attachment 1 demonstrates that load balancing price variances are only recorded in months where there are actual Dawn supply purchases. To the extent that there are no actual Dawn supply purchases in a given month, there are no load balancing price variances allocated to customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, p. 2, plus Attachment

Question(s):

For each month, please provide:

a) The percentage of gas that was delivered whose price was fixed (i.e., not indexed)
b) For those amounts of fixed-price gas, please provide the dates that prices were transacted to a fixed price

Response:

a-b)

Please see Table 1.

Table 1
2024 Monthly Fixed Price Gas Purchase Detail

Line No.	Month	2024 Actual Ontario Delivered Supplies (10^3m^3) (1)	Monthly % Fixed Price Purchases	Date of Fixed Price Purchase (2)
1	January	563,210 (Indexed Price)	0%	N/A
2	February	377,039 (Indexed Price)	0%	N/A
3	March	0	0%	N/A
4	April	0	0%	N/A
5	May	0	0%	N/A
6	June	0	0%	N/A
7	July	0	0%	N/A
8	August	0	0%	N/A
9	September	0	0%	N/A
10	October	25,555 (Fixed Price) 25,554 (Fixed Price) 25,554 (Fixed Price) 76,663	33% 33% 33% 100%	October 9, 2024 October 17, 2024 October 23, 2024
11	November	25,986 (Fixed Price) 32,032 (Indexed Price) 58,018	44% 0% 44%	November 4, 2024 N/A
12	December	82,148 (Fixed Price) 115,008 (Fixed Price) 28,752 (Fixed Price) 229,675 (Indexed Price) 455,583	18% 25% 6% 0% 49%	November 26, 2024 December 3, 2024 December 10, 2024 N/A
13	Total	1,530,513	21%	

Notes:
(1) Exhibit D, Tab 1, Schedule 1, Attachment 1, column (a).
(2) Intra-month purchases or purchases made after the close of the monthly index are typically transacted as fixed price purchases.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, Table 1

Question(s):

For each of the respective rate zones, please provide a monthly breakdown of:

a) the amount of capacity released, and
b) the revenue generated by that released capacity.

Response:

a-b) Please see Table 1 for a monthly breakdown of capacity released to the market along with associated revenue generated.[1]

[1] As explained in Note 1 to Enbridge Gas's Updated Evidence at Exhibit E, Tab 1, Schedule 1, Table 1, Line No. 1, "Capacity Released (TJ)" refers to total actual UDC volumes, a portion of which are capacity volumes released by the Company to the market. Also included in total actual UDC volumes are instances where no UDC cost is incurred (e.g., while planned Volumes for Dawn South are reflected as UDC volumes, there is no pipeline capacity required for these volumes, no UDC costs, and no capacity available to release), UDC volumes associated with curtailment/interruptions that occurred, and where the capacity was not released by the Company to the market because it was operationally required (please see response at Exhibit I.FRPO-30). Exhibit E, Tab 1, Schedule 1, Table 1, Line No. 3, "Actual Released Capacity Revenue ($000s)" refers to revenues generated from capacity volumes released by the Company to the market.

Table 1
Capacity Released to the Market Monthly Breakdown

Line No.	Particulars	Capacity Released (TJ)	Released Capacity Revenue ($000s)
	(a)	(b)	(c)
	Union North East		
1	-	-	-
	Union North West		
2	Apr-24	287	69
3	May-24	855	255
4	Jun-24	3,158	1,661
5	Aug-24	1,696	873
6	Sep-24	1,161	613
7	Oct-24	514	399
8	Total	7,670	3,871
	Union South		
9	Jun-24	1,583	79
10	Jul-24	1,635	62
11	Aug-24	1,635	67
12	Sep-24	1,583	54
13	Oct-24	1,635	71
14	Total	8,071	333

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, Table 1

Question(s):

Specific to the UGL Northeast, please provide a monthly summary of exchanges performed by EGI, including:

a) the amount of capacity used, and
b) the amount of optimization revenue generated.

Response:

a) Please see Attachment 1.

b) Exchange revenue is not tracked as requested. Please see the response at Exhibit I.FRPO-1, Table 1. The majority of the optimized revenue generated for the Union North East Rate Zone was based upon Waddington exchanges.

Table 1
Union North East Summary of Exchanges

Line No.	Path	January Volume (GJ)	February Volume (GJ)	March Volume (GJ)	November Volume (GJ)	December Volume (GJ)
1	Parkway - Waddington	1,128,285	967,023	117,838	952,679	1,332,100
2	Parkway - East Hereford	5,734	6,497	5,338	-	-
3	Parkway - Niagara	52,461	-	-	-	-
4	Parkway - Napierville	-	-	-	7,385	92,504
5	Total	1,186,480	973,520	123,176	960,064	1,424,604

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, Table 1

Question(s):

Please confirm that the remaining refund from the Panhandle pipelines was, or will be, refunded to ratepayers through the QRAM.

a) Please provide the details associated with the refund.

Response:

Confirmed.

As reported in Enbridge Gas's October 2024 QRAM filing[1], Enbridge Gas received an additional $5.3 million refund from the Panhandle pipeline toll dispute. Of this refund, $4.7 million was included as a reduction to gas cost in the Union South PGVA[2] and approximately $0.6 million was included as a credit in the Unabsorbed Demand Charge Variance Account. The refund was credited to the appropriate rate zones in alignment with the historic allocation of UDC costs.[3]

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[1] EB-2024-0245, Exhibit D, Tab 1, Schedule 1, pp.1-2.
[2] EB-2024-0245, Exhibit E, Tab 1, Schedule 2, p.5, Column (a), Line 11.
[3] Exhibit E, Tab 1, Schedule 1, p.5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, Table 1

Question(s):

For each of the three rate zones in the union territory please provide a monthly breakdown of the capacity released by path (e.g., Empress to Union EDA).

a) Does EGI Gas Control department (or other operating group responsible for nominations) have nominating rights to both the EGD and UGL rate zones?

b) Can deliveries to the EGD rate zone be diverted to Iroquois while deliveries to the UGL rate zone be diverted to the EGD rate zone?

   i. Has EGI used this approach?

Response:

Please see Attachment 1 for a monthly breakdown of the capacity released to the market by path.[1]

a) Yes, Enbridge Gas has the right to nominate to both the EGD rate zone and Union rate zones.

b) Enbridge Gas has the ability to nominate Firm Transportation (FT) services to the EGD rate zone and Union rate zones using its FT contracts on the TransCanada Mainline from Empress to its respective delivery areas for which the contract

[1] As explained in Note 1 to Enbridge Gas's Updated Evidence at Exhibit E, Tab 1, Schedule 1, Table 1, Line No. 1, "Capacity Released (TJ)" refers to total actual UDC volumes, a portion of which are capacity volumes released by the Company to the market. Also included in total actual UDC volumes are instances where no UDC cost is incurred (e.g., while planned Volumes for Dawn South are reflected as UDC volumes, there is no pipeline capacity required for these volumes, no UDC costs, and no capacity available to release), UDC volumes associated with curtailment/interruptions that occurred, and where the capacity was not released by the Company to the market because it was operationally required (please see response at Exhibit I.FRPO-30).

relates. These contracts also allow Enbridge Gas to nominate to all other delivery areas using diversions or interruptible transportation services which are not firm and have a higher risk of curtailment relative to FT.

i. No. Enbridge Gas's preference is to contract for firm transportation services to meet the needs of its customers rather than rely on diversions or interruptible transportation services which are not firm and have a higher risk of curtailment by comparison.

Capacity Released to the Market by Path

Line No.	Particulars	Receipt Point	Delivery Point	Capacity Released (TJ)
	(a)	(b)	(c)	(d)
	Union North East			
1	-	-	-	-
	Union North West			
2	Apr-24	Empress	Centrat MDA	167
3	Apr-24	Empress	Union WDA	120
4	May-24	Empress	Centrat MDA	173
5	May-24	Empress	Union SSMDA	124
6	May-24	Empress	Union WDA	558
7	Jun-24	Empress	Centrat MDA	167
8	Jun-24	Empress	Union SSMDA	210
9	Jun-24	Empress	Union WDA	1,085
10	Jul-24	Empress	Centrat MDA	173
11	Jul-24	Empress	Union SSMDA	217
12	Jul-24	Empress	Union WDA	1,307
13	Aug-24	Empress	Centrat MDA	173
14	Aug-24	Empress	Union SSMDA	217
15	Aug-24	Empress	Union WDA	1,307
16	Sep-24	Empress	Centrat MDA	167
17	Sep-24	Empress	Union SSMDA	150
18	Sep-24	Empress	Union WDA	845
19	Oct-24	Empress	Centrat MDA	173
20	Oct-24	Empress	Union WDA	341
21	Total			7,670
	Union South			
22	Jun-24	Vector	Dawn	1,583
23	Jul-24	Vector	Dawn	1,635
24	Aug-24	Vector	Dawn	1,635
25	Sep-24	Vector	Dawn	1,583
26	Oct-24	Vector	Dawn	1,635
27	Total			8,071

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, Table 1

Question(s):

How does EGI make the decision as to whether to release some of the capacity to the TCPL EDA or to use it for optimization exchanges? Please explain fully.

Response:

Enbridge Gas did not release TCPL capacity to the Union EDA in 2024. Long-haul capacity to the Union EDA is generally not released due to the low cost of natural gas supply at Empress and considering the STS credits generated through its use. Short-haul capacity to the Union EDA is generally not released as it has great operational value and minimal release value during the summer months.

Monthly, Enbridge Gas assesses customer demands relative to its pipeline capacity and may release unutilized capacity to the market where there is value. Enbridge Gas assesses customer demands daily relative to its remaining pipeline capacity (i.e., that was not released) to serve each delivery area. Any surplus capacity is made available for optimization (exchanges) purposes, including TCPL capacity to the Union EDA.

ENBRIDGE GAS INC.

Answer to Interrogatory from
City of Kitchener (Kitchener)

Interrogatory

Reference:

Exhibit E, Tab 2, Schedule 1, Appendix A Page 1 of 1 line 15:
In the table, Enbridge Gas mentioned storage deliverability for T3 rate as 68,472 GJ/day.

Question(s):

a) Please explain the detail calculation behind the storage deliverability quantity of 68,472 GJ/day.

b) Please confirm the customer deliverability quantity parameter and DCQ quantity in the T3 contract during the year?

Response:

a) The total Union South Rate Zone storage deliverability of 1,808,097 GJ/d, shown at line 16, column (b) of Exhibit E, Tab 2, Schedule 1, Appendix A represents the total Union South Rate Zone storage deliverability based on forecast W24/25 requirements. The deliverability is calculated as total Union South Rate Zone demands, less total supplies and market-based deliverability.

   The allocation of the storage deliverability amount to Union South Rate Zone rate classes is done using OEB-approved cost allocation methodologies for the allocation of storage deliverability related costs. Please see Attachment 1.

   Enbridge Gas notes that the allocation of storage space and deliverability to rate classes as shown in Exhibit E, Tab 2, Schedule 1, Appendix A is based on allocation factors per EB-2019-0194, Exhibit B-1, Appendix C1 for the Union Rate Zone and EB-2017-0086, Exhibit G2, Tab 6, Schedule 3 for the EGD Rate Zone and may not reflect current contracted parameters. Enbridge Gas does not calculate storage space and deliverability allocation factors on an annual basis.

b) For the period January 1, 2024 to December 31, 2024, the contracted customer deliverability for Rate T3 was 49,000 GJ/d.

For the period January 1, 2024 to December 31, 2024, the obligated DCQ for Rate T3 was 11,400 GJ/d at Dawn and 17,268 GJ/d at Parkway.

Allocation of Union South Rate Zone Storage Deliverability

Line No.	Particulars	Storage Deliverability Allocation Factor (1) (10^3m^3/day)	(%)	Allocation of W24/25 Forecast Storage Deliverability (2)
		(a)	(b)	(c)
	Union South Rate Zone			
1	Rate M1	22,551	52.9%	956,568
2	Rate M2	7,237	17.0%	306,977
3	Rate M4	3,964	9.3%	168,159
4	Rate M5	7	0.0%	281
5	Rate M7	1,529	3.6%	64,875
6	Rate M9	215	0.5%	9,121
7	Rate M10	3	0.0%	140
8	Rate T1	932	2.2%	39,528
9	Rate T2	4,573	10.7%	193,978
10	Rate T3	1,614	3.8%	68,472
11	Total Union South Rate Zone	42,627	100.0%	1,808,097

Notes:

(1) Storage deliverability allocation factor (NETFROMSTOR) per EB-2019-0194, Exhibit B-1, Appendix C1.

(2) Allocated in proportion to column (b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

Enbridge notes that Included with the Application, Enbridge Gas is providing the OEB Scorecard, the Indigenous Working Group Report, the Integrated Resource Planning (IRP) Annual Report and the IRP Technical Working Group Report, and Distribution Integrity Management Program and Enhanced Distribution Integrity Management Program Report on Activities. No approval is being sought regarding these items.

a) Please confirm that Enbridge is not expecting OEB approval of the above noted reports as part of this proceeding.

b) If Enbridge submits that the supplemental reports noted above are not relevant to the clearance of any of the accounts, how does Enbridge propose that the reports be considered and assessed by the OEB for purpose of this proceeding?

Response:

a) Confirmed.

b) Enbridge did not submit that the supplemental reports noted above are not relevant to the clearance of any of the accounts.

   In some cases, information within the reports may be relevant to the clearance of accounts (for example, the Distribution Integrity Management Program Variance Account and the Indigenous Working Group Deferral Account).

   Generally speaking, however, the OEB scorecard and various reports provided are for supplemental information purposes only. No specific OEB approval of either the OEB scorecard or the informational reports is being sought. The scorecard and the reports included in evidence are filed in response to Enbridge Gas commitments or OEB directions in prior proceedings.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

As set out in the 2024 Rebasing Phase 1 Decision, the ESM does not apply for 2024, as that is a cost of service year. Accordingly, there is no ESM amount proposed for 2024. [A/2/1, page 2]

Question(s):

Since Enbridge notes that the ESM does not apply for 2024, what purpose does Enbridge intend in the application for including the calculations in Exhibit B related to 2024 earnings and return?

Response:

While the ESM does not apply for 2024, Enbridge Gas felt it was appropriate, as it has in the past, to report 2024 utility results as provided in Exhibit B as a standard set of schedules for informational purposes and to maintain the annual continuity of utility results reporting.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2.

Question(s):

Utility Rate Base (line 5) in Enbridge's calculation is noted as 16,025.3 million. Please confirm that this exceeds the OEB approved value for 2024 and explain why the OEB approved value was not used for the calculations.

Response:

Yes, the $16,025.3 million actual 2024 Utility Rate Base value exceeds the OEB approved value for 2024. The OEB approved value represents the forecast Utility Rate Base that was used for ratemaking purposes and setting base rates for the 2024 Test Year. Actual Utility Rate Base, along with actual utility income, cost of debt, etc., has been used to determine the actual 2024 Utility Return on Equity (ROE), which is compared to the OEB-approved benchmark ROE (ie. 9.21% approved ROE that was reflected in rates) to show the variance between actual and forecast 2024 utility results.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

a) Please provide a list of the 2023 and 2024 costs related to the Parry Sound IRP Pilot Project that are included in the accounts identified in the application.

b) Were any of the Parry Sound IRP Pilot Project costs (noted in part a above) included in the OEB approval under EB-2022-0335? If yes, please indicate which amounts and the related activities. If no, please provide any other OEB approval references related to Parry Sound IRP Pilot Project costs.

Response:

a) Table 1 is a list of the 2023 and 2024 costs related to the Parry Sound IRP Pilot Project that are included in the IRP Operating Costs Deferral Account.

Table 1
Parry Sound IRP Pilot Project Costs

Line No.	Activities	2023 ($000s)	2024 ($000s)
1	Stakeholdering	$3.6	--
2	Administrative/Legal	$21.9	$6.3
3	Data Collection and Analysis	$0.5	$0.5
4	CNG	$0.3	$14.0
5	Total	$26.3	$20.8

b) The Parry Sound IRP Pilot Project costs were not sought for OEB approval under EB-2022-0335. The Parry Sound IRP Pilot Project was withdrawn from the updated IRP Pilot Project application. The amended application outlined that costs related to the development of the Parry Sound Pilot Project would be recorded in the IRP Operating Costs Deferral Account[1] and this balance is requested for clearance within this proceeding.

[1] EB-2022-0335, Exhibit E, Tab 1, Schedule 2, p.1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 11, Table 2.

Question(s):

a) For the IRP metrics included in Table 2, please confirm the filing reference for the AMP version used to calculate those metric results (i.e. is it the most current AMP filed under EB-2021-0091?).

b) If a more recent AMP has been filed, please explain why the most recently filed AMP was not used.

c) Enbridge notes that "87% of the investments that passed Binary Screening have been fully assessed". Does that mean that 13% have passed the screening and are at the final project economic evaluation IRP stage? If no, please explain what it means.

d) How many projects does the 87% value represent?

Response:

a) The IRP metrics included in Table 2 correspond to the 2025-2034 AMP filed on November 8, 2024 under EB-2020-0091. This is not the latest AMP filing, which is the 2026 AMP Addendum filed October 30, 2025.

b) The 2025-2024 AMP was the most recent AMP available for the 2024 IRP Deferral Account evidence. IRP metrics corresponding to the 2026 AMP Addendum will be filed in the 2025 IRP Deferral Account evidence in 2026.

c-d) The 87% represents 1,185 of the 1,359 investments that passed binary screening and were fully assessed for IRP and were either technically screened or evaluated out of the process for IRP.

The 13% represents 174 of the 1,359 investments that passed binary screening and were pending either technical or economic evaluation.

The details of the IRP screening and evaluation results are summarized in Exhibit G, Tab 2, Schedule 1, page 8, Figure 3.2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

The purpose of the DIMPVA is to track Enbridge Gas's spending each year on the DIMP and EDIMP programs. Parties agreed that $12.5 million is included in the 2024 O&M budget for these programs, and that variances will be recovered from or credited to ratepayers on an annual basis from 2024 until Enbridge Gas's next rebasing. [C/2/13, page 1]

Question(s):

a) Are the activities and related costs included in DIMP and EDIMP net new activities or are they activities that have historically be included in other program areas and are now moved under DIMP and EDIMP?

b) Please provide the methodology on how Enbridge determines which costs to include under the DIMP or EDIMP programs for purposes of allocating these costs against the $12.5 million 2024 budget and DIMPVA. If a manual or guidance was developed to assist staff in identifying what costs should be allocated to DIMP, EDIMP and/or the DIMPVA, please provide a copy and any related training materials.

Response:

a) The activities and related costs included in the Distribution Integrity Management Program Variance Account (DIMPVA) comprise both net new activities and activities that were previously recorded under other program areas.

   Enhanced Distribution Integrity Management Program (EDIMP) is a subprogram of DIMP and represents net new activities. It was launched in 2024 following the establishment of the DIMPVA under the OEB's Decision on the 2024 Rebasing Phase 1 Settlement Agreement. [1] DIMP, which predates the creation of the DIMPVA, is a subprogram of Enbridge's Integrity Management Program (IMP). As a result, DIMP related costs were historically captured in other programs and have since been transitioned to the DIMPVA.

[1] EB-2020-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023.

b) All O&M costs associated with the DIMP and EDIMP programs are allocated to the DIMPVA.

The DIMP scope includes all gas carrying distribution assets from upstream custody transfer points (i.e., gate stations) to downstream customer meters, including the following:

- Pipe: Gas distribution mains operating at <30% Specified Minimum Yield Strength (SMYS), headers, services, risers, valves, fittings (excluding EDIMP pipelines as described below)
- Stations: Distribution system stations (excluding FIMP scope) and customer stations
- Regulator Sets: Farm taps, commercial and residential meter sets, service extensions

The EDIMP scope includes distribution steel pipelines that meet one or more of the following criteria:

- Operate at 20% to 30% SMYS
- Are classified as vital mains or equivalent
- Have a Maximum Operating Pressure (MOP) ≥ 1200 kPa (175 psi) and a pipe diameter ≥ NPS 6

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

Please explain why the approximately $12.5 million spent on DIMP/EDIMP related work in 2024 did not lead to any Asset Life Extension opportunities for capital assets.

Response:

Asset Life Extension (ALE) opportunities resulting from the 2024 DIMP/EDIMP work are expected to begin in 2026. As described in Exhibit G, Tab 4, Schedule 1, page 12, each pipeline inspected under EDIMP in 2024 will undergo a quantitative risk assessment (QRA) in 2025, with long-term mitigation activities commencing in 2026. Any resulting ALE opportunities will begin to be reported in the 2025 DIMP/EDIMP Report on Activities.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

a) Please explain the reasons and drivers for the resulting weather normalized variations (debits/credits) across each of the rate classes included in the Average Use Variance Account for 2024.

b) It is unclear why there is such a large difference in impact across rate classes. Was any analysis done to reconcile the variances across the different rate classes? If yes, please provide a copy of the materials (analysis, reports, presentations, memos, etc.).

Response:

a - b)
Please refer to Attachment 1, Figures 1 to 6, which present a graphical comparison of actual weather-normalized average use for the period 2010 to 2024 and the 2024 budget average use for each of the following rate classes: Rate 1, Rate 6, Rate M1, Rate M2, Rate 01, and Rate 10. All values shown have been normalized to 2024 budget degree days for comparability.

The actual vs budget percentage variances calculated based on Exhibit C, Tab 2, Schedule 17, Attachment 1, lines 1 and 2 are approximately as follows: Rate 1: +1.3%; Rate 6: -0.7%; Rate M1: -2.5%; Rate M2: -14.3%; Rate 01: +1.5%; and Rate 10: -15.2%.

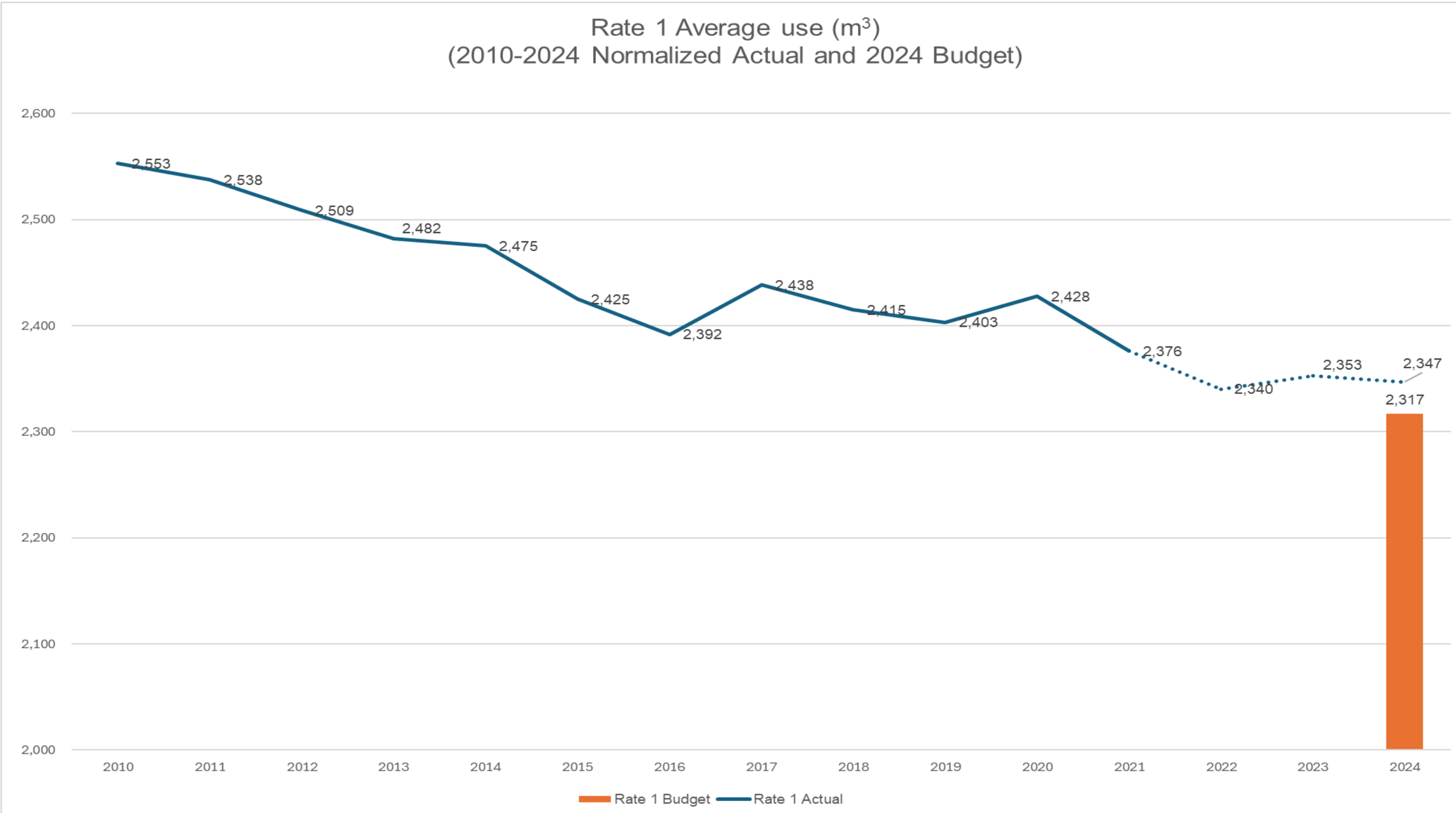
The variances for Rate 1, Rate 6, Rate M1, and Rate 01 represent relatively modest forecast errors that fall within the range of variation typically observed in annual average use forecasting. These levels of deviation are considered indicative of acceptable forecast performance given the inherent uncertainty associated with economic activity and customer consumption behavior.

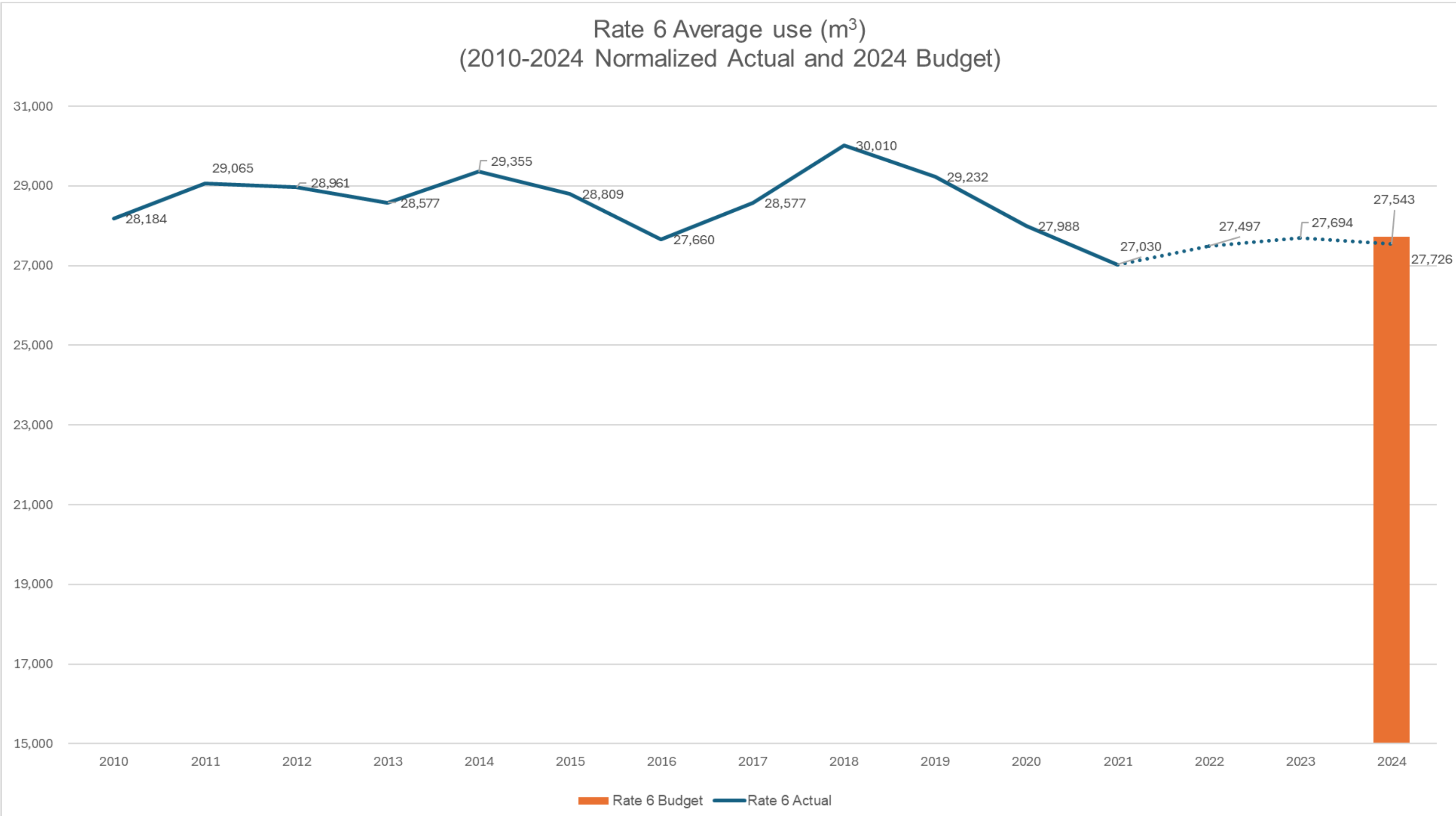
In contrast, the 2024 variances for Rate M2 and Rate 10 reflect higher forecast errors relative to historical patterns. As illustrated in Attachment 1, Figures 4 and 6, the average annual changes in Rate M2 and Rate 10 average uses between 2010 and 2019 were -0.3% and +1.5%, respectively. However, between 2019 and 2021, average use for these classes declined at a significantly faster pace, with average annual reductions of 5.5% for Rate M2 and 6.2% for Rate 10.

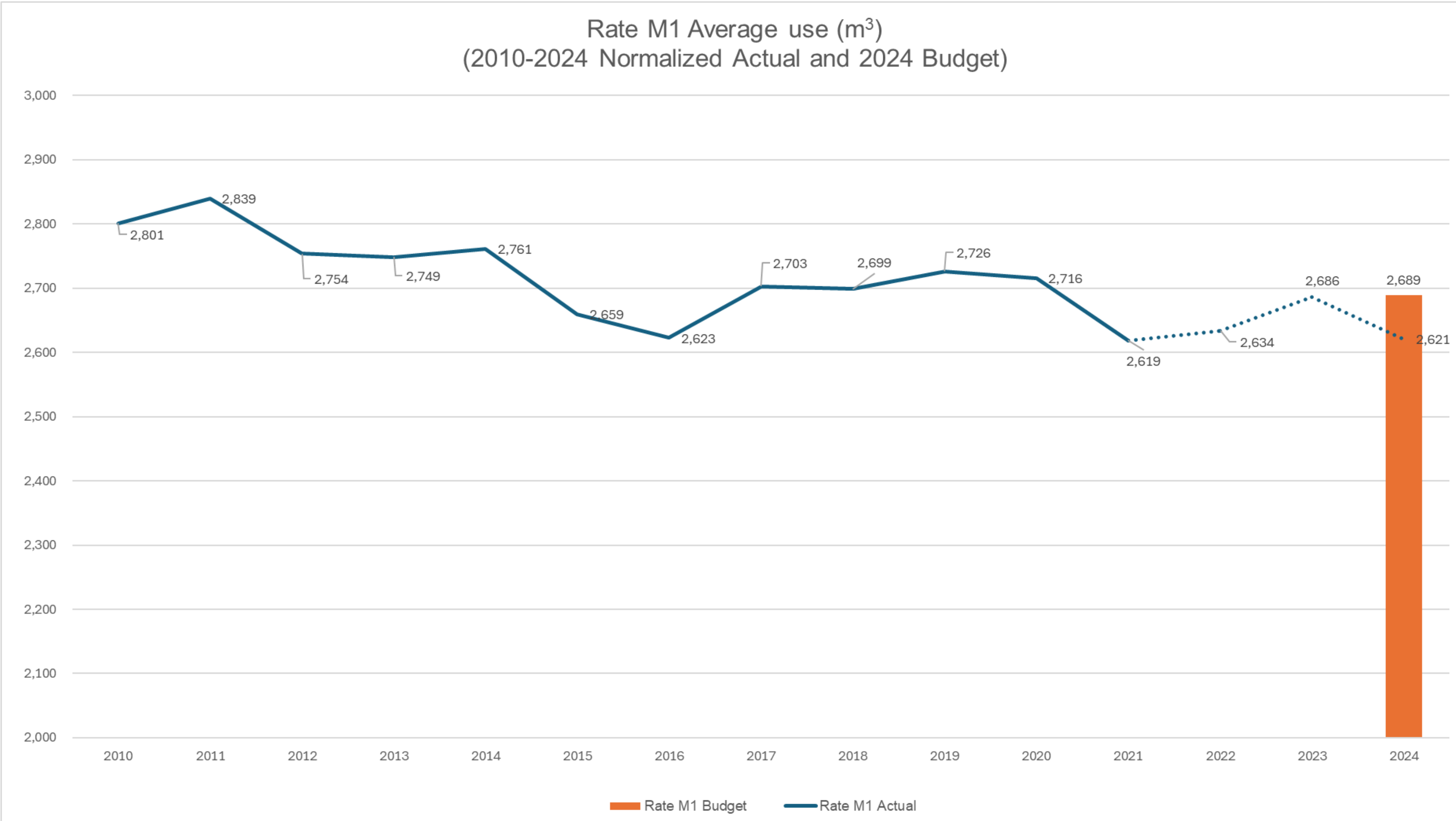
When preparing the 2024 forecast[1], Enbridge Gas assessed that these steeper-than-normal declines were primarily attributable to the impacts of the COVID-19 pandemic. Consistent with the Company's forecasting approach, and in the absence of evidence supporting a permanent structural shift, it was reasonable to expect average use for these classes to revert toward historical trend levels over the forecast horizon.

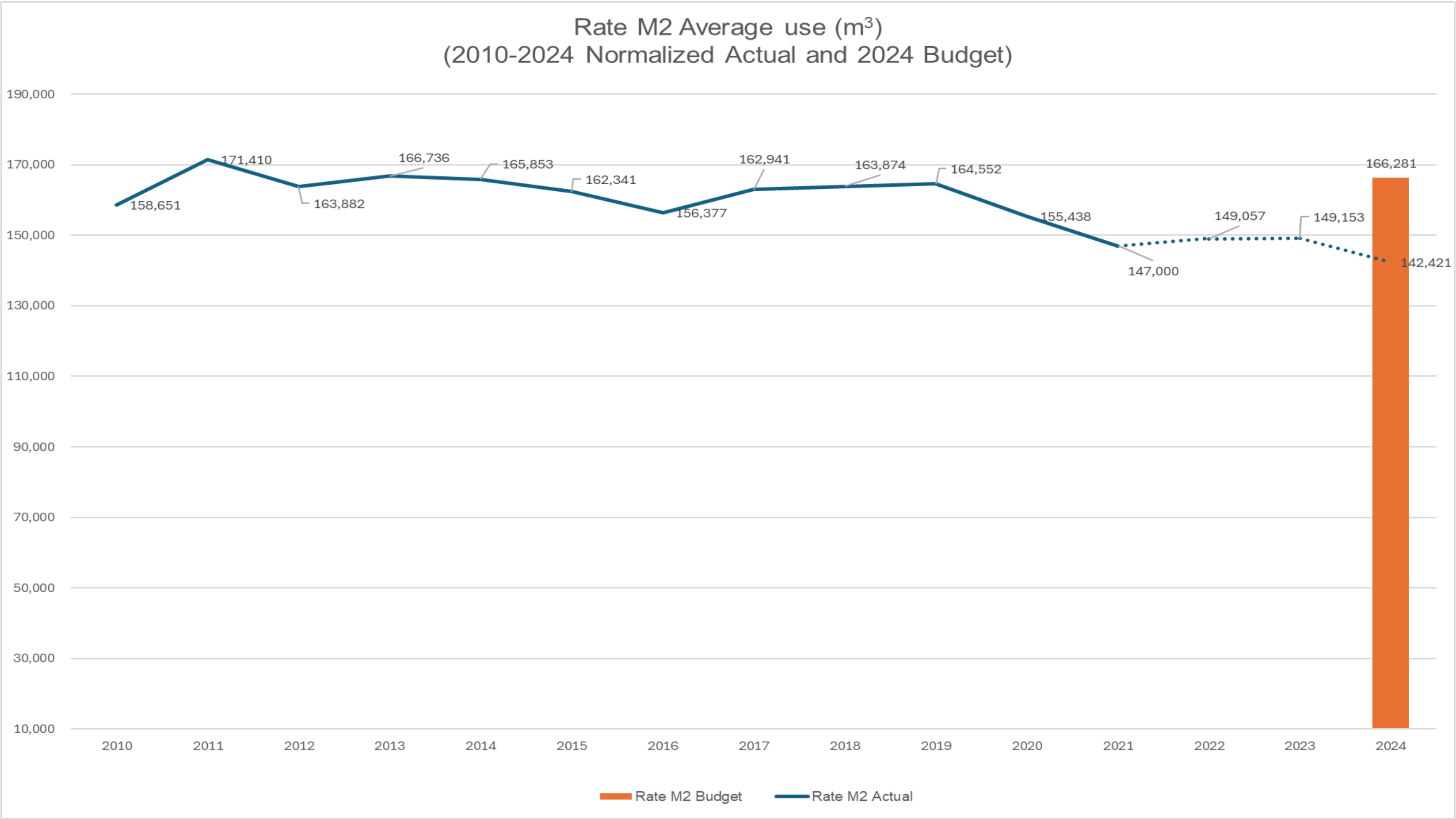
As noted in the 2024 Rebasing Phase 1 proceeding[2], unexpected shocks or structural breaks are outside the Company's control and may occur under any forecasting methodology. Enbridge Gas will continue to monitor the recent changes in average use trends for the affected rate classes as additional actual data becomes available.

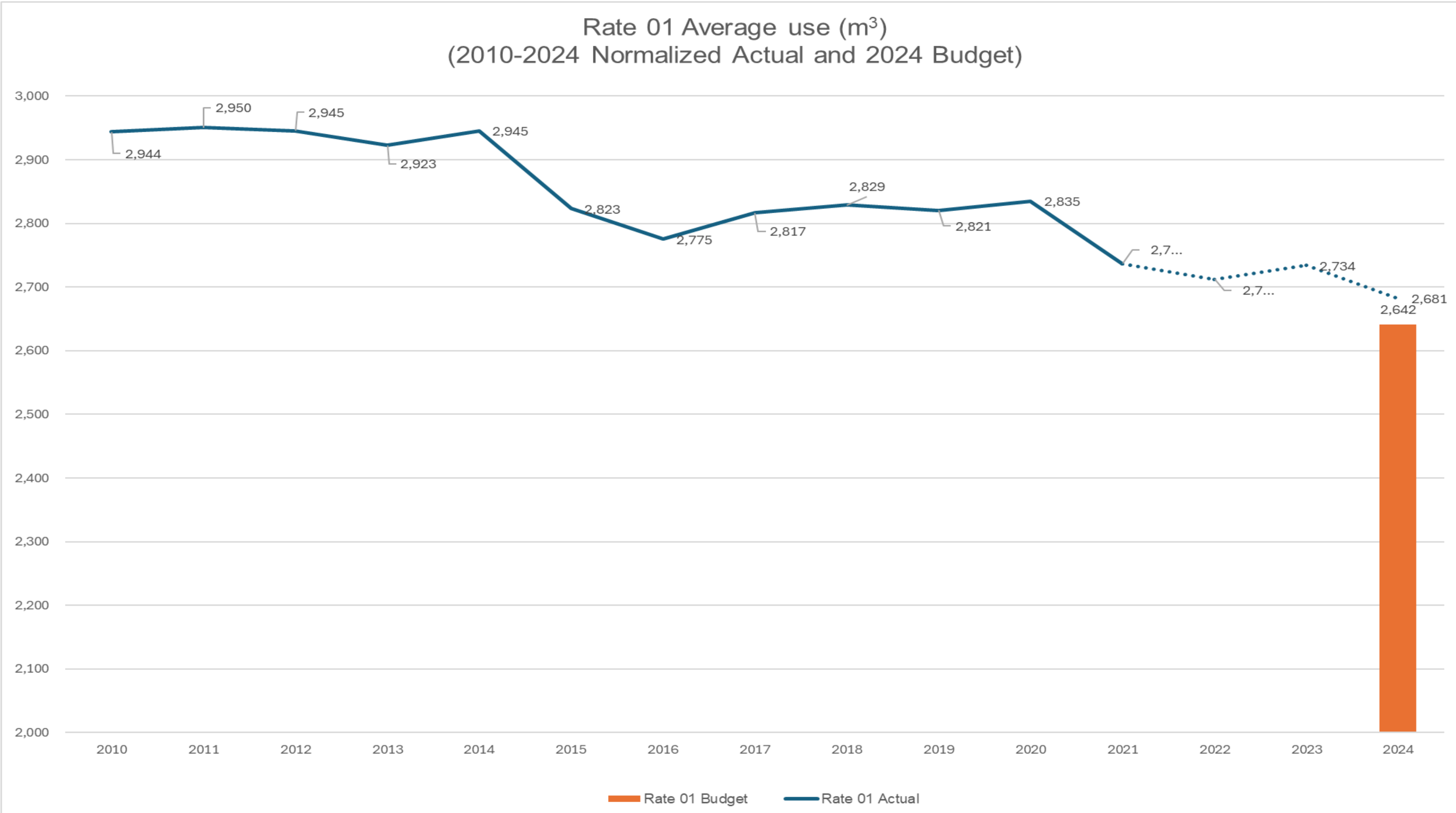
[1] 3-yr ahead forecast due to 2024 Rebasing Phase 1 Application (EB-2022-0200) using actuals up to 2021 instead of standard 2-yr ahead forecast in rate applications within the IRM term.
[2] EB-2022-0200, Exhibit 3, Tab 2, Schedule 5, p.13, footnote 25.


Rate 1 Average use (m^3)
(2010-2024 Normalized Actual and 2024 Budget)
2,600
2,500
2,400
2,300
2,200
2,100
2,000
2,553
2,538
2,509
2,482
2,475
2,425
2,392
2,438
2,415
2,403
2,428
2,376
2,340
2,353
2,347
2,317
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Rate 1 Budget
Rate 1 Actual


Rate 6 Average use (m^3)
(2010-2024 Normalized Actual and 2024 Budget)
31,000
29,000
27,000
25,000
23,000
21,000
19,000
17,000
15,000
28,184
29,065
28,961
28,577
29,355
28,809
27,660
28,577
30,010
29,232
27,988
27,030
27,497
27,694
27,543
27,726
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Rate 6 Budget
Rate 6 Actual


Rate M1 Average use (m^3)
(2010-2024 Normalized Actual and 2024 Budget)
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2,100
2,000
2,801
2,839
2,754
2,749
2,761
2,659
2,623
2,703
2,699
2,726
2,716
2,619
2,634
2,686
2,621
2,689
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Rate M1 Budget
Rate M1 Actual


Rate M2 Average use (m3)
(2010-2024 Normalized Actual and 2024 Budget)
190,000
170,000
150,000
130,000
110,000
90,000
70,000
50,000
30,000
10,000
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
158,651
171,410
163,882
166,736
165,853
162,341
156,377
162,941
163,874
164,552
155,438
147,000
149,057
149,153
142,421
166,281
Rate M2 Budget
Rate M2 Actual


Rate 01 Average use (m3)
(2010-2024 Normalized Actual and 2024 Budget)
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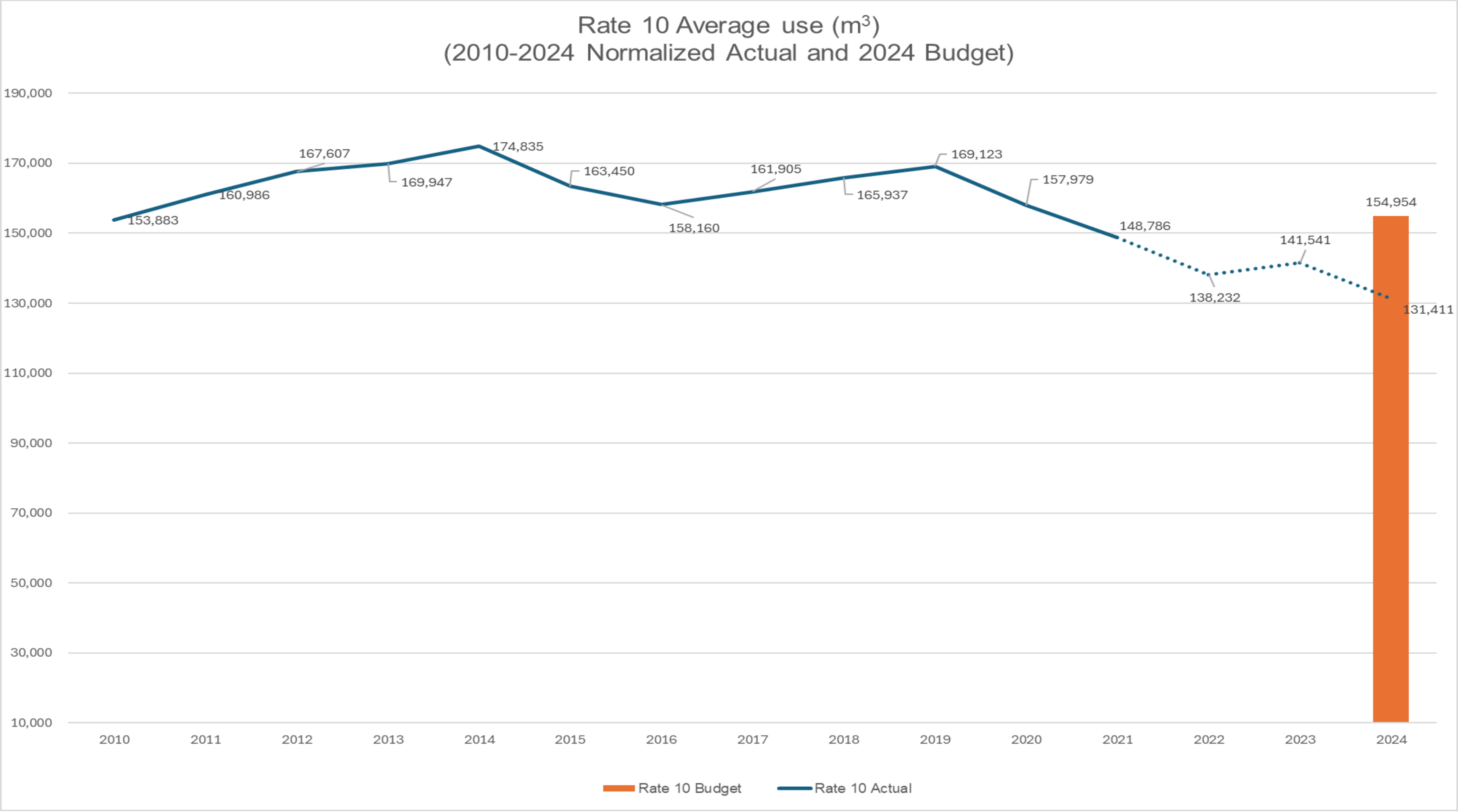
2,900
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2,100
2,000
2,944
2,950
2,945
2,923
2,945
2,823
2,775
2,817
2,829
2,821
2,835
2,7...
2,7...
2,734
2,681
2,642
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Rate 01 Budget
Rate 01 Actual


Rate 10 Average use (m3)
(2010-2024 Normalized Actual and 2024 Budget)
190,000
170,000
150,000
130,000
110,000
90,000
70,000
50,000
30,000
10,000
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
153,883
160,986
167,607
169,947
174,835
163,450
158,160
161,905
165,937
169,123
157,979
148,786
138,232
141,541
131,411
154,954
Rate 10 Budget
Rate 10 Actual

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Enbridge Sustain Affiliate Recoveries Variance Account

Question(s):

a) Please confirm that Enbridge Sustain is no longer operating as a line of business within Enbridge Gas (as of September 30, 2024).

b) Please explain the current scope of operations of Enbridge Sustain and if there has been a significant change to this line of business?

c) If there have been significant changes to the Enbridge Sustain line of business (e.g. downsizing), what was the involvement of Enbridge Gas to provide goods and services to support those changes.

d) Enbridge noted that the largest variance driver for 2024 O&M is due to $48.3 million in severance costs. What portion of those severance costs are related to staff that worked for or had an allocation to support Enbridge Sustain?

e) Please provide the amounts paid by Enbridge Sustain to Enbridge Gas for severances paid and related administrative services. Please indicate what line item in Table 1 (C/2/19, page 2) those costs were included in for purposes of transfer reconciliation.

Response:

a) As of October 1, 2024, Enbridge Sustain is no longer operating as a line of business within Enbridge Gas.

b-c) In the 2024 Rebasing Phase 2 evidence submission, Enbridge Gas confirmed:

> The products and services offered by Enbridge Sustain are expected to include the following: geothermal heating and cooling systems, hybrid heating systems, solar power generation, electric vehicle charging, and large

scale retrofit projects. Overall, these products aim to support customers seeking to use new end-use technology options.[1]

Beginning in October 2024, following Enbridge Sustain's move to an affiliate, the business broadened its residential HVAC portfolio beyond hybrid heating solutions to include a wider range of heating, cooling, and water-heating products. There was no "downsizing" during 2024.

In mid-2025, Enbridge Sustain made a strategic decision to streamline operations and focus on areas with stronger, more immediate demand. If relevant, changes made during 2025 will be detailed in the 2025 Utility Earnings and Disposition of Deferral & Variance Account Application, to be filed later this year.

d) None of the $48.3 million in severance costs are related to staff that worked for or had an allocation to support Enbridge Sustain.

e) No amounts were paid by Enbridge Sustain to Enbridge Gas for severances paid and related administrative services in 2024.

[1] EB-2024-0111, Phase 2, Exhibit 1, Tab 18, Schedule 1, pp.1-2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Enbridge Gas, in consultation with the IRP Technical Working Group (TWG) engaged Det Norske Veritas (DNV) Canada Ltd. to conduct a jurisdictional scan on system pruning activities. [C/2/20, page 10]

Question(s):

Please provide a copy of the contracted scope of work for the jurisdictional scan noted above.

Response:

Please see Attachment 1.

2024

System Pruning Jurisdictional Scan

ENBRIDGE GAS – REQUEST FOR QUOTATION

OCTOBER 2024

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Introduction

Enbridge Gas is seeking the services of an external consultant to perform a jurisdictional scan of system pruning activities. The objective of this report is to provide a greater understanding and obtain insights into how gas utilities among North American and European jurisdictions, where informative to the Ontario context, are approaching pruning of their gas distribution pipelines. This report is intended to provide Enbridge Gas, the IRP Technical Working Group (IRP TWG) and the Ontario Energy Board (OEB) with a foundational understanding of system pruning approaches, best practices and lessons learned to assist in the development of a potential system pruning framework and pilot in Ontario.

Background

In the Phase 1 Decision to Enbridge Gas' Rebasing Application (EB-2022-0200), the OEB introduced the concept of system pruning as a way to reduce system. System pruning involves the strategic and proactive decommissioning of a portion of the natural gas system through education and/or incentivization of existing customers to willingly disconnect from the gas system, thus rendering that specific portion of the pipeline no longer required to serve their energy needs. System pruning will also avoid capital costs associated with replacing a section of the distribution pipeline system once customers have fully disconnected from the system. To proceed with the pruning of a targeted portion of the system, all customers served by that pipeline system must have fully converted off natural gas and be willing to disconnect from the pipeline system. The OEB gave the example of "converting a subdivision from gas to electricity for space and water heating" and stated that system pruning could be supported by an IRP solution, which would include supporting existing customers in replacing their gas equipment with electric equipment to avoid the need the replace the facility.[1]

In its Phase 2 Evidence, Enbridge Gas outlined its approach to system pruning to include engagement with the IRP TWG to consult on system pruning processes and what role the Company could play in a system pruning pilot. To inform this work, Enbridge Gas noted it would complete a scan to identify how utilities in other jurisdictions are approaching gas system pruning to identify best practices, where available.

IRP Technical Working Group Engagement

Enbridge Gas intends to work collaboratively with the selected consultant and members of the IRP TWG (collectively or a subcommittee) throughout the jurisdictional scan process. The Consultant and all participating members are expected to follow the norms set forth by the Terms of Reference of the TWG.[2] As part of their quote, the Consultant should include regular meetings to receive input on and review progress of the study. The quote should indicate the number and timing of TWG meetings with justification.[3]

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[1] EB-2022-0200, Decision and Order, December 21, 2023, p.52.
[2] Terms of Reference
[3] The actual number and timing of meetings will be determined jointly by Enbridge and OEB staff with input from the consultant.

For clarity, in terms of approach:

- The Study is being conducted for, and on behalf of, Enbridge Gas, OEB Staff, other members of the IRP Working Group and, ultimately, all Enbridge ratepayers.
- Where non-contractual or administrative decisions are required for the Consultant through the course of the jurisdictional scan, they will be informed by the information/recommendations of the Consultant and in consultation with the members of the IRP TWG (collectively or a subcommittee). If the members cannot reach consensus, the Consultant shall review feedback and make the decision, taking into account all comments and discussions, as well as the approved scope and budget. The Consultant will document any disputed issues within the final deliverables along with the Consultant's position, Enbridge Gas's position and the other members' positions.
- With the exception of communications related solely to the contractual or other administrative issues between the Consultant and Enbridge Gas, all written communications between the Consultant and TWG members shall be copied to the subcommittee (if used) or all members (if no subcommittee). Similarly, a summary of any oral communications will also be shared by the Consultant.
- If a subcommittee is used, members will be selected by OEB Staff in conjunction with the TWG. The Consultant will not participate in the selection process.
- Any member of the IRP TWG who works for the Consultant's firm will be representing their firm during jurisdictional scan discussions. For other topics, they will continue to represent themselves as individuals, not a representative of a specific organization.
- If a subcommittee is used, the Consultant will coordinate jurisdictional scan meetings that involve TWG subcommittee members. The meetings will also be attended by OEB Staff. The Consultant will chair the meetings, circulate agenda items, and record key meeting outcomes. The outcomes will not be posted to the OEB website but will be accessible upon request to any TWG members, including those not participating on the subcommittee. The consultant will keep OEB Staff informed of the expected participation time of IRP TWG members and work with OEB Staff to resolve any concerns regarding the expected participation time. Updates on the progress of jurisdictional scan work will be provided to the full IRP TWG at the regular IRP TWG meetings, with discussion documented in meeting minutes and posted to the OEB website.
- The selected consultant will be responsible for the final materials delivered as a result of the jurisdictional scan. OEB Staff will post the deliverables on the IRP TWG website.

Study Objectives

1. Landscape assessment to identify which jurisdictions are undertaking gas system pruning projects.
2. Targeted research of utilities to conduct a deeper dive on gas decommissioning strategies and practices, supplemented with 1:1 interviews with utility staff, government staff, and/or regulatory staff to discuss process and experience.

3. Final report on each utilities' processes and identification of emerging best practices/practices to avoid across utilities, lessons learned, and information gaps.

Scope of the Study

The scope of the study includes the following areas:

Task 1 – Landscape Assessment

Jurisdictional landscape assessment to identify which jurisdictions or utilities are pursuing gas system pruning and, depending on the number of jurisdictions pursuing this, select a subset to conduct a deeper dive for the purposes of this report. The number of jurisdictions selected will be informed by the landscape assessment, the stage that the identified jurisdictions are at with respect to their considerations and action on system pruning, and the degree of potential insight and transferability of learnings to Ontario.

Deliverables include providing a list of the jurisdictions or utilities pursuing system pruning or gas decommissioning, and highlighting the stage they are at and any system pruning initiatives undertaken.

Task 2 – Identification of Targeted Utilities

Based on the results of the landscape assessment, this task will include developing the Consultant's recommendation for the subset of jurisdictions and utilities for the targeted research stage to conduct a deeper dive into their system pruning processes, with associated justification for the jurisdictions included (and excluded where relevant) based on the results of the landscape assessment. The Consultant will work with Enbridge Gas and the IRP TWG to confirm the structure of the report, and key questions for 1:1 interview with utility employees and other stakeholders as required.

Deliverables include providing a list of targeted utilities with recommendation and justification for the targeted research stage, draft structure of the report, and key interview questions.

Task 3 – Targeted Research and Interviews

Within selected jurisdictions, targeted research and interviews will be conducted to take a deeper dive of their gas decommissioning strategies and practices through secondary research, supplemented with direct communication with utility staff to provide further learnings (to be conducted with both an Enbridge Gas staff and TWG representative in attendance. To further understand the jurisdictional context, interviews with government or regulatory staff (or other active stakeholders) may be included. This will cover the following areas from the intended scope of the report, including:

- Jurisdictional context and background, including regulatory decisions, gas planning frameworks, and government legislation related to gas decommissioning planning and projects.

- Utility objectives and/or drivers underpinning the pursuit of system pruning activities (e.g. rate of expenditure on pipeline integrity potentially influenced by materials that have been in use in the jurisdiction, utility/customer/jurisdictional considerations like size/type of utility, customer make-up, regional construction practices, climate, and utility/customer decision-making drivers).
- An overview of each utilities' approach to system pruning projects and/or programs including:
    - The screening criteria (if any) to identify potential pipeline candidates, and associated process considerations.
    - The criteria and methodology to prioritize and select feasible potential pipeline candidates (including whether any verification of the information driving the investment need avoided through pruning that segment of the system).
- Utility structure (i.e., gas-only, joint gas/electric), and the extent to which natural gas utilities pursuing system pruning are coordinating those efforts with affected electric utilities, as well as the nature of any such coordination.
- The methodology to evaluate the cost effectiveness of pruning to compare alternatives.
- Customer engagement practices throughout the process, from assessing initial customer sentiment for potential candidate systems through to strategies for achieving participation and disconnection from the gas system.
- Policies and strategies for "hold outs" in situations where most customers are prepared to fully electrify but a very small number or portion are not.
- Funding sources for system pruning projects (i.e., electric ratepayer, gas ratepayer, government).
- Program design and offer to customers, inclusive of the scope of non-gas building and water heating alternatives (e.g. electric heat pumps, thermal networks, requirements around not supporting transition to higher-emissions fuels) and partnership considerations and how barriers are addressed.
- Deployment plan and associated program delivery approaches
- Summary of projects completed to date or anticipated to be completed (number of completed projects and, for each such project, the pipe characteristics, number and type of customers attached, time horizon for project completion, costs, any gas system cost savings, challenges, successes experienced, etc.).
- Utility incentives to implement system pruning/how disincentives have been addressed.
- How the costs of proposed alternatives are treated for rate making purposes, how the costs are recovered, and any changes to utility rate design.

Deliverables include a summary of research, interview questions and responses in Word format.

Task 4 – Identification of Commonalities and Divergence Across Jurisdictions

The section will identify key areas of commonality and divergence across the identified jurisdictions, and to the extent possible the drivers behind them. This will cover the following areas from the intended scope of the report, including:

- The screening criteria to identify potential pipeline candidates, and associated process considerations.
- The criteria and methodology to prioritize and select feasible potential pipeline candidates.
- Coordination and integration processes between natural gas and electric utilities.
- The methodology to evaluate the cost effectiveness to compare alternatives.
- Customer engagement practices along the process, from assessing initial customer sentiment for potential candidate systems through to strategies for achieving participation and disconnection from the gas system.
- Policies and strategies for “hold outs” in situations where most customers are prepared to fully electrify but a very small number or portion are not.
- Funding sources for system pruning projects (i.e., electric ratepayer, gas ratepayer, government).
- Program design and offer to customers, inclusive of scope of non-gas building heating alternatives (e.g. electric heat pumps, thermal networks, requirements around not supporting transition to higher-emissions fuels)
- Deployment plan and associated program delivery approaches.
- Key elements of projects completed to date or anticipated to be completed (pipe characteristics, number and type of customers attached, time horizon, costs, challenges and successes experienced, etc.).
- Utility incentives to implement system pruning.
- How the costs of proposed alternatives are treated for rate making purposes, how the costs are recovered, and any changes to utility rate design.

Deliverables includes summary of findings.

Task 5 – Emerging Best Practices

This section will identify a set of emerging best practices among the utilities studied. Best practice is defined, for the purpose of this report, as a practice either documented in a utility report or stated by an interviewee as contributing to program success for at least one of the utilities reviewed, and ideally across multiple utilities. For example, may include but not limited to strategies on the following components:

- Criteria and methodology to prioritize candidates.
- Coordination among gas and electric utilities (i.e., planning tools).
- Customer engagement practices.
- Policies and strategies for "hold outs".
- Program design and deployment practices.

Deliverables includes summary of findings.

Task 6 – Identification of Lessons Learned

This section will provide an overview of lessons learned and barriers to success either identified in a utility report or stated by an interviewee. For example, may include but not limited to discussion such as:

- Process learnings internal to the utility.
- Key findings from projects initiated and completed.
- Barriers experienced such as findings on customer preferences and key factors impacting opt-in participation for gas decommissioning projects.

Deliverables includes summary of findings.

Task 7 – Information Gaps

This section will include what information was missing, unclear or unable to be obtained through the execution of this work. This may include an overview of the encountered limitations in information available in the targeted jurisdictions, any context on challenges encountered, and any considerations in light of these limitations.

Deliverables includes summary of findings.

Task 8 – Final Report

Deliverable includes a final report consolidating all research findings, and discussion of identified commonalities/divergence, lessons learned, and best practices, to be provided in Word format.

Deliverables

Consultant should provide the following deliverables:

1. Landscape Assessment showing all jurisdictions implementing gas decommissioning.
2. List of recommended jurisdictions and utilities for the targeted research stage.
3. Research results and interview findings for targeted jurisdictions/utilities, including interview questions, notes and responses.
4. Summary of system pruning commonalities/divergence, best practices, lessons learned, and information gaps across jurisdictions.
5. Final Report – consolidation of all research and findings.

Proposed Schedule

The following schedules and deadlines apply:

Request for Quotation Issued	November 1, 2024
Quotation Due Date	November 6, 2024
Notice of Contract Award	November 13, 2024

Quotation Format

1. Approach & Methodology
    - Provide a description of any recommendations of the Consultant towards the objectives outlined that differ from the tasks and approach outlined in the study scope.
2. Study Timeline & Cost Estimate
    - Provide the proposed study timeline in table format.
    - Provide a budget table for all major phases and milestones of the study, broken out by task. Please include the hourly rate and estimated number of hours for each project team member in the budget table. Additionally, please include the hourly rate for potential Regulatory support (as required), inclusive but not limited to witness and interrogatory support.
3. Study Team
    - Identify the proposed project team by personnel and task.

Please submit quotation to:

David Moffat – david.moffat@enbridge.com

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Enbridge Gas will work with the IRP Technical Working Group to identify one or two system pruning pilot projects, which will be implemented by 2026. [EB-2024-0111 Exhibit N, Tab 1, Schedule 1, Page 11]

Question(s):

a) Please confirm that the system pruning pilot project(s) noted in the 2024 OEB approved settlement agreement has been implemented prior to 2026. If not, please explain why not.

b) Please confirm that the 2024 costs related to the system pruning pilot project(s) will be brought forward for clearance as part of the 2025 deferral and variance account clearance application. If not, when does Enbridge propose to bring those costs forward for consideration?

Response:

a) Confirmed, Enbridge Gas has begun implementation. For clarity, the 2024 Rebasing Phase 2 Settlement Agreement outlines that "Enbridge Gas will develop its approach to system pruning in consultation with the IRP Technical Working Group by the end of Q2 2025 and begin implementation on one or two pilots by the end of Q1 2026."[1]

b) Confirmed.

[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, pp.19-20.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

Please provide an update and details on any costs incurred by Enbridge related to the second IRP pilot project required by the OEB and where those costs are recorded.

Response:

Please see response at Exhibit I.PP-4 part a) for the 2023 and 2024 costs related to the Parry Sound IRP Pilot Project that was ultimately withdrawn from the updated IRP Pilot Project Application. The OEB's IRP Pilot Project Decision[1] ordering Enbridge Gas to consider a second pilot project was not issued until March 2025. As such, this does not bear on the 2024 year that is the subject of review in this proceeding.

In any event, Enbridge Gas has not incurred any costs related to a new second IRP pilot project.

The OEB is currently reviewing the IRP Framework[2]. It is premature to engage in further IRP pilot projects until there is guidance from the IRP Framework Review process.

Additionally, on December 22, 2025 Enbridge Gas filed a Notice of Motion to review and vary portions of the EB-2022-0335 Decision. The variance sought includes the direction to consult on a potential second IRP pilot pending further direction from the current and ongoing IRP Framework Review and requests a stay of the Decision in relation to the review issues until the Review Motion is determined.

[1] EB-2022-0335, OEB Decision, March 27, 2025.
[2] EB-2025-0125.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

There are currently 15.5 IRP full-time equivalent (“FTE”) roles, where these resources directly support the implementation of the IRP Decision. [G/2/1, page 4].

Question(s):

a) Please provide the list of positions included in the 15.5 FTEs and the % allocation for each.

b) Please provide the IRP allocated FTEs from 2021 to 2024 and provide a summary explanation on where any increases have been allocated.

Response:

a) Table 1 provides the list of positions included in the 15.5 FTEs. Each FTE is allocated 100% to IRP.

Table1
2024 IRP FTEs

Line No.	Role	Department	Number of FTEs
1	Specialist II	Asset Management	1
2	Senior Engineer	Distribution Optimization Engineering (DOE)	1
3	Specialist	DOE	1
4	Supervisor	DOE	1
5	Senior Advisor	DSM	1
6	Specialist	Finance	1
7	Senior Advisor	Finance	1
8	Senior Analyst	IRP	1
9	Advisor	IRP	1
10	Specialist	IRP	1
11	Supervisor	IRP	1
12	Manager	IRP	1
13	Senior Advisor	Municipal and Stakeholder Engagement	1
14	Advisor	Municipal and Stakeholder Engagement	2
15	Engineer	Storage and Transmission	0.5
16	Total FTEs		15.5

b) The allocation of IRP FTEs from 2021 to 2024 is not relevant to the approvals sought in this proceeding. All 2024 IRP positions provided in part a) are part of base O&M and the increase relative to the prior level in base O&M was canvassed in the 2024 Rebasing Phase 1 proceeding[1].

[1] EB-2022-0200.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

IRP Assessment Screening and Evaluation Guidelines [G/2/1, page 96]

Question(s):

a) There does not appear to be a version date on the cover of the IRP Assessment Screening and Evaluation Guidelines. Please confirm what the version date is for this document and if there were previous versions filed.

b) Is this the first application where this IRP Assessment Screening and Evaluation Guidelines document has been filed. If not, please provide the reference for where this document was filed.

c) Was the IRP Assessment Screening and Evaluation Guidelines (noted above) reviewed and approved by the OEB IRP TWG? If yes, please provide a copy of the documentation noting the review and approval. If not, why not?

d) Has the OEB approved the IRP Assessment Screening and Evaluation Guidelines noted above? If yes, please provide a copy of the approval reference. If no, when does Enbridge intended to seek OEB approval for this document?

Response:

a-b) The version date of the IRP Assessment Screening and Evaluation Guidelines is aligned with the July 4, 2025 filing date of the 2024 IRP Annual Report.[1] Previous versions of this document were filed on July 2, 2024, as part of 2023 Annual Report[2] and on April 6, 2023, as part of 2024 Rebasing Phase 1.[3]

c) The IRP TWG reviews and provides feedback on the draft IRP Annual Report, inclusive of the IRP Assessment Screening and Evaluation Guidelines, in advance of the filing of the IRP Annual Report. The IRP TWG does not have an approval role.

[1] EB-2025-0064, Exhibit I.1.13-ED-4, Attachment 1.
[2] EB-2024-0125, Exhibit H, Tab 1, Schedule 1.
[3] EB-2022-0200, Exhibit JT5.36, Attachment 2.

d) The OEB has not approved the IRP Assessment Screening and Evaluation Guidelines. As outlined in the IRP Framework, the OEB does not approve the IRP Annual Report. Enbridge Gas is not seeking OEB approval for this document and there is no directive or planned application to seek approval. Changes in IRP requirements relative to the current IRP Framework would be determined in the IRP Framework review consultation.[4]

[4] EB-2025-0125.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

What is the current status and proposed completion date for the Southern Lake Huron IRP Pilot Project?

Response:

The Southern Lake Huron IRP Pilot project was launched in the field as Sarnia Saves.[1,2] The status of the full suite of pilot offers is provided in Table 1.

[1] The Sarnia Saves website for all SLH IRP Pilot commercial offers is accessible at www.enbridgegas.com/sarniasaves/business
[2] The Sarnia Saves website for all SLH IRP Pilot residential offers is accessible at www.enbridgegas.com/sarniasaves

Table 1
Status of Southern Lake Huron IRP Pilot Offers

Line No.	Southern Lake Huron IRP Pilot offers	Status
1	Commercial and Industrial Custom	Launched July 31, 2025
2	Residential Whole Home	Launched September 22, 2025
3	Residential Single Measure Attic Insulation	Launched September 22, 2025
4	Residential Limited Electrification	Launched September 22, 2025 at the limited participation levels proposed by Enbridge Gas in the Application. Enbridge Gas has stayed redirection of funds relating to advanced natural gas technologies to electrification until direction on the Review Motion is determined. Please see response at Exhibit I.PP-12.
5	Commercial and Industrial Direct Install	Launched October 8, 2025
6	Commercial and Industrial Prescriptive Downstream	Launched October 8, 2025
7	Residential Demand Response	Enbridge Gas is completing all pre-launch requirements and expects to launch mid-February 2026
8	Residential Advanced Gas Technologies	Not approved in the OEB Decision and at issue in the Review Motion as noted above.

All launched offers have a proposed market completion date of December 31st, 2026. Demand Response has a proposed market completion date of March 31, 2027. The final pilot report is expected to be completed at the end of Q4 2027.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Southern Lake Huron Pilot Program reports [G/2/1, pages 286 and 291]

Question(s):

Were the Southern Lake Huron Pilot Program documents (noted above) reviewed and approved by the OEB IRP TWG? If yes, please provide a copy of the documentation noting the review and approval. If not, why not?

Response:

These documents were reviewed and discussed with the Integrated Resource Planning Technical Working Group (IRP TWG) over the course of several IRP TWG meetings as outlined below. The IRP TWG does not have an approval role. The expectation of the OEB was for Enbridge Gas to engage with the IRP TWG in developing the project plan.[1]

At IRP TWG Meeting #52, Enbridge Gas presented the Southern Lake Huron (SLH) IRP Pilot Plan template, a timeline for when all SLH IRP Pilot Plan sections would be distributed to the IRP TWG for feedback, and the date of the future IRP TWG meetings where these items and IRP TWG comments would be discussed. Enbridge Gas committed to incorporating TWG member suggestions into the draft SLH IRP Pilot Plan, as appropriate.[2]

At IRP TWG Meeting #53, Enbridge Gas provided an update on the SLH IRP Pilot Objective 1 (how enhanced targeted energy efficiency and demand response programs impact peak hour flow/demand).[3]

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[1] EB-2022-0335, OEB Decision and Order, March 27, 2025, p.7.
[2] IRP TWG Meeting Notes, Meeting #52, April 23, 2025, https://engagewithus.oeb.ca/28744/widgets/145694/documents/152324
[3] IRP TWG Meeting Notes, Meeting #53, May 7, 2025, https://engagewithus.oeb.ca/28744/widgets/145694/documents/153171

At IRP TWG Meeting #54, Enbridge Gas presented the timing of how IRP TWG member feedback on the 2024 IRP Annual Report, inclusive of the SLH IRP Pilot Plan, would be requested and discussed.[4]

On May 26, 2025, Enbridge Gas distributed a draft of the SLH Pilot Plan to IRP TWG members for review and written comments. This included the SLH Pilot Objective 1 draft table of contents and RFQ, and the Evaluation Plan for SLH Pilot Objective 2 (how to design, deploy, and evaluate enhanced targeted energy efficiency and residential demand response programs).

At IRP TWG Meeting #55 Enbridge Gas provided an overview of the SLH Pilot Plans, addressed written comments and held further discussion.[5]

The revised SLH IRP Pilot Plan informed by this consultation was included as Appendix G of the 2024 IRP Annual Report.

[4] IRP TWG Meeting Notes, Meeting #54, May 21, 2025, https://engagewithus.oeb.ca/28744/widgets/145694/documents/155399
[5] IRP TWG Meeting Notes, Meeting #55, https://engagewithus.oeb.ca/28744/widgets/145694/documents/156739