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September 5, 2024

VIA RESS AND EMAIL

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2024-0125
2023 Utility Earnings and Disposition of Deferral & Variance Account Balances – Interrogatory Responses

In accordance with the OEB's Procedural Order No. 1 dated, July 22, 2024, 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	Confidential Information Location	Brief Description	Basis for Confidentiality
I.PP-6	Attachment 1 pg. 9	Scope of Work The redacted information is hourly and task-specific pricing information.	This is information that the OEB has indicated will be presumptively considered to be confidential – Billing rates and/or unit pricing of a third party.[1]
I.PP-11	Attachment 1 pgs. 13 and 31	Consulting Agreement The redacted information is hourly and task-specific pricing information.	This is information that the OEB has indicated will be presumptively considered to be confidential – Billing rates and/or unit pricing of a third party
I.PP-13	Attachment 1 pg. 3	Scope of Work The redacted information is pricing information.	This is information that the OEB has indicated will be presumptively considered to be confidential – Billing rates and/or unit pricing of a third party

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

Enbridge Gas received an additional interrogatory filed confidentially. Enbridge Gas would like to inform the OEB and parties that the response to the interrogatory will be filed in the next few days.

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-2024-0125 Intervenors

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Utility Earnings Calculation Exhibit B, Tab 1, Schedule 1-2

Question(s):

a) Is the calculation of utility earnings consistent with the methodology used to calculate the earnings in prior years? If not, please explain any differences and provide rationale for any deviations from the approach used in prior years.

b) Does Enbridge Gas submit its ROE to the OEB as part of its annual RRR filings?
   i. Are the ROE calculations used for the RRR and in this utility earnings calculation consistent with each other? If not, please explain why there is a divergence.

Response:

a) Yes, the calculation of utility earnings is consistent with the methodology used to calculate earnings in prior years.

b) Yes, Enbridge Gas submits its ROE to the OEB as part of its annual RRR filings. The ROE calculations used for the RRR and utility earnings calculation are intended to be consistent with each other. Enbridge Gas notes that the preliminary ROE as provided in 2023 RRR 2.1.5 on April 30th was a draft of the results as at that date. The final utility results and ROE were subsequently updated and submitted as final as part of this proceeding at Exhibit B, Tab 1, Schedules 1-2. On August 19, 2024, Enbridge Gas provided an update to OEB Staff for RRR 2.1.5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Utility Operating and Maintenance Exhibit B, Tab 3, Schedule 1, p. 1-3 & Appendix A

Preamble:

Enbridge stated that O&M expenses increased by $106.5 million primarily due to higher Miscellaneous Expense, Compensation and Benefits, DSM, Materials and Supplies. Table 1 was provided to show the Utility's O&M expense categories for the 2022-2023 actuals.

Miscellaneous Expense (Line 16) increased $283.4 million over the prior year primarily due to impairment charges related to the OEB Settlement and Phase 1 rebasing decisions driven by the pension balance write-off ($156.1 million), write-off of net capital integration costs ($84.3 million), and GTA/WAMS capital write-offs ($41.0 million). The pension write-off of $156.1 million is considered non-utility cost and is eliminated on Line 25.

Compensations and Benefits (Line 1) increased by $26.9 million over the prior year from an $11.0 million increase in merit. An increase of $5.3 million was driven by higher Operations and Customer Care FTEs.

Question(s):

a) Please provide references showing approval for Enbridge Gas to write off the items in the Miscellaneous Expenses (i.e. Pension balance, capital integration and GTA/WAMS).

b) Please provide the rationale of a $26.9 million increase in merit in 2023 compared to $11.0 million in the year before.

c) Please provide the actual number of FTEs for Operations and Customer Care as of January 1, 2023 and December 31, 2023.

    i. How does the average additional FTE cost in Operations and Customer Care compare to the average FTE cost of Enbridge Gas.

Response:

a) In its Decision and Order for the Company's 2024 Phase 1 Rebasing application dated December 21, 2023, the OEB stated that it "denies Enbridge Gas's proposed recovery of $156 million of Pension & OPEB expenses as recorded in the APCDA for the pre-2017 Union unamortized actuarial gains/losses."[1] As a result of the Decision and Order, Enbridge Gas was required under US GAAP[2] to recognize an impairment loss at the time of the Decision and Order and therefore, the impairment loss was recognized as part of the 2023 Enbridge Gas Consolidated Statements of Earnings.

   Also, in its Decision and Order, the OEB stated that it "disallows the addition of the undepreciated integration capital in the amount of $119 million to rate base. This amount shall not be recoverable from ratepayers."[3] Similar to the Pension balance above, as a result of the Decision and Order, Enbridge Gas was required under US GAAP[4] to recognize an impairment loss at the time of the Decision and Order and therefore, the impairment loss was recognized as part of the 2023 Enbridge Gas Consolidated Statements of Earnings.

   In its Decision on Settlement Proposal for the 2024 Phase 1 Rebasing application, dated August 17, 2023, the OEB stated that it "accepts the updated partial settlement proposal, as filed on July 14, 2023."[5] Within the Settlement Proposal it was noted that:

   > Parties accept Enbridge Gas's rate base up to and including 2022, subject to, (i) agreement to remove the forecast residual net book values of the overspend on the WAMS project and 25% of the overspend on the Enbridge Gas Distribution GTA Reinforcement Project from opening rate base for 2024.[6]

   As a result of the Decision on Settlement Proposal, similar to the decision noted above regarding the pension balance, Enbridge Gas was required under US GAAP[7] to recognize an impairment loss at the time of the Decision and Order and therefore, the impairment loss was recognized as part of the 2023 Enbridge Gas Consolidated Statements of Earnings.

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[1] EB-2022-0200, Decision and Order, December 21, 2023, p.106.
[2] ASC 980-340-40-1: If at any time an entity's incurred cost no longer meets the criteria for capitalization of an incurred cost, that cost shall be charged to earnings.
[3] EB-2022-0200, Decision and Order, December 21, 2023, p.76.
[4] ASC 980-340-40-1: If at any time an entity's incurred cost no longer meets the criteria for capitalization of an incurred cost, that cost shall be charged to earnings.
[5] EB-2022-0200, Settlement Agreement, August 17, 2023, p.5.
[6] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.25.
[7] ASC 980-340-40-1: If at any time an entity's incurred cost no longer meets the criteria for capitalization of an incurred cost, that cost shall be charged to earnings.

b) Please see Exhibit B, Tab 3, Schedule 1, page 3, paragraph 8 for a detailed explanation of $26.9 million total compensation increase which is inclusive of the following,

1. $11.0 million increase in merit
2. $5.3 million increase in Operations and Customer Care FTEs
3. $9.0 million increase in business unit benefits due to higher FTEs and pension expense

The rationale for the $11 million increase in merit compared to the year before is base pay levels are reviewed on an annual basis following company guidelines which awards increases based on individual performance and pay range placement within an approved, market-aligned annual base salary (merit) budget.[8]

c) The actual FTE for Operations and Customer Care as of January 1, 2023 is 1678.7 and 278.7.

The actual FTE for Operations and Customer Care as of December 31, 2023 is 2027.5 and 282.7.

As described in evidence, during 2023, the Operations FTE increases contributing to higher compensation and benefits costs were to address COVID_19 labour shortages. The other main driver of FTE increases in Operations was due to an organizational restructuring where several departments mainly Storage and Transmission Operations were transferred into the Operations department. These are transferred costs and would not impact to the compensations and benefits year over year.

i) The average FTE cost of Operations is lower than the average FTE cost of Enbridge Gas and average FTE cost of Customer Care is higher than average FTE cost of Enbridge Gas.

[8] Please see EB-2022-0200, Exhibit 4, Tab 4, Schedule 3, p.11, para.28 for more details.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Enbridge Gas – Integrated Resource Planning (IRP) Operating Cost Deferral Account
Exhibit C, Tab 1, pp. 14-22

Preamble:

The balance in the 2023 IRP Operating Costs Deferral Account that is being requested for clearance within this proceeding is a debit of $3.081 million, plus forecast interest of $0.247 million, for a total debit of $3.328 million. This amount is attributable to incremental Enbridge Gas staff salaries including expenses for IRP related work performed in 2023, the implementation of Integrated Resource Plan Alternatives (IRPA(s)) to defer a project in Kingston and non-labour costs such as consulting and legal costs.

The incremental work that has arisen for the organization because of implementing the OEB's IRP Decision includes binary screening and technical evaluations, economic analysis, development and implementation of IRP stakeholder engagement activities and regulatory support.

Question(s):

a) Please provide the list of cost savings arising from Enbridge Gas's IRP activities.

b) How have Enbridge Gas's IRP activities benefitted ratepayers to date to justify the proposed disposition at the cost of ratepayers? How would IRP activities benefit ratepayers in the future?

    i. How, if at all, does Enbridge Gas take into consideration the achieved and expected benefits to ratepayers of its IRP activities, in establishing its budget or level of spending for IRP activities (outside of any costs associated with specific approved IRP Plans)? Please describe Enbridge Gas's general approach, and its approach with reference to 2023 spending in particular (i.e., the costs recorded in the 2023 IRP Operating Costs Deferral Account).

c) How did the IRP annual report and the IRP Technical Working Group report inform Enbridge Gas's request for disposition?

d) Has the OEB provided any guidance regarding an appropriate budget or level of spending on Enbridge Gas's IRP activities (outside of any costs associated with specific approved IRP Plans), either in the original IRP Decision and Order, or other Enbridge Gas proceedings? If so, please describe.

Response:

a) Enbridge Gas has implemented one IRP alternative to-date, the East Kingston Creekford Rd Project. When the project was implemented, it allowed for the East Kingston Creekford Rd Project to be delayed from 2024 until 2027. As displayed in Appendix C of the 2023 IRP Annual Report, the East Kingston Creekford Rd growth related project is no longer within the 10-year Asset Management Plan (AMP).[1]

   As noted in Enbridge Gas's 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances application[2] the proposed project addressed three project drivers, inclusive of increased forecasted demands driven by growth, depth of cover and class location. The project delay and subsequent removal of the East Kingston Creekford Rd Project from the 10-year AMP enabled avoided planned capital costs of $24.3 million for this capital reinforcement; however, the depth of cover and class location related issues will continue to be monitored and assessed and, if required, the project will be brought back into the 10-year AMP.

   The O&M Costs for the supply side CNG alternative, inclusive of 2022 to 2024, are $0.63 million.[3]

b) Please see the response at Exhibit I.STAFF-3 part a) for the avoided capital costs and O&M expenditure associated with the IRP alternative implemented to-date.

   i. Enbridge Gas must comply with the OEB's Decision and Order for Integrated Resource Planning[4]. This Decision requires Enbridge Gas to conduct the IRP Screening and Evaluation process, which is ongoing, with the objective of determining the preferred solution – Facility Alternative(s), IRP Alternative(s) or a combination of the two – to meet specific system needs in a manner that considers the best interests of Enbridge Gas and its customers. The costs included in the 2023 IRP Operating Costs Deferral Account represent the

[1] Exhibit H, Tab 1, Schedule 1, Appendix C, pg.36.
[2] EB-2023-0092, Exhibit C, Tab 1, p. 21.
[3] The total CNG O&M costs of $0.63M was incurred across 2022 to 2024, where the cost per year is $0.08M, $0.28M, and $0.27M for each respective year. For clarity, costs in 2022 and 2023 have been included in previous/current Deferral Clearance applications request for disposition, and 2024 costs will be disposed of accordingly with the 2024 Deferral Clearance application.
[4] EB-2020-0091, Decision and Order, dated July 22, 2021.

costs to complete the work necessary to comply with the established IRP framework and these costs are not wholly dependent upon whether an IRP Alternative is determined to be the best alternative and implemented. As outlined at Exhibit C, Tab 1, pages 15 - 22, these include costs related to resources, the East Kingston Creekford Road project, modelling enhancements and stakeholder engagement. This approach has and will continue to benefit ratepayers through enabling Enbridge Gas to proceed as directed by the OEB with IRP as a planning strategy and process that considers Facility Alternatives and IRP Alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations, and identify and implement the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management.

c) The annual IRP report and the report from the IRP Technical Working Group are filed for information purposes for the OEB and stakeholders. They did not inform Enbridge Gas' request for disposition but rather include information on IRP activities undertaken for which Enbridge Gas is seeking disposition.

d) No, the OEB has not provided this guidance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Enbridge Gas – Getting Ontario Connected Act Variance Account Exhibit C, Tab 1, Schedule 1, pp. 23-25

Preamble:

Enbridge Gas stated, "[b]ased on 2021 external contractor costs Enbridge Gas was expecting to pay approx. $34 per locate in 2023, however the actual cost paid for a locate rose to $72 a 111% increase over expectation."

Enbridge also stated, "[a]s mentioned above, the 2021 average external contractor cost per locate was $34 and the 2023 average external contractor cost per locate was $72, a 111% increase."

For the vital main standby (VMS), the 2021 average external contractor, using the same personnel as locates, cost per hour was $82 and the 2023 average external contractor cost per hour was $146, a 78% increase.

Question(s):

a) Please provide references to the 2021 external contractor cost to pay per locate.

b) Please clarify if the $34 was the average 2021 cost or was it the cost Enbridge Gas was expecting to pay in 2023 based on its 2021 external contractor cost.

c) Why are the increase in costs of locates (111%) and VMS (78%) not the same if the same contractors are being used?

d) Please confirm that Enbridge Gas uses the Price Cap Index, similar to the annual IRM increase, to forecast the cost of the external contractor cost.

Response:

a) The average cost in 2021 was $32 per locate.

b) $34 is what Enbridge Gas was expecting to pay in 2023 based on the 2021 Price Cap Index (PCI) inflation adjusted external contractor cost.

c) Despite being performed by the same contractor the activities are billed differently. VMS is billed at an hourly rate and locates are billed per locate with differing costs based on various locating factors.

d) Not confirmed. Enbridge Gas typically applies a standard inflation rate to forecast annual external contractor costs. This rate is provided by Enbridge Inc. and based off CPI study/analysis.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

2023 Storage & Transportation Deferral Account - EGD Exhibit D, Tab 1, p. 1-2

Preamble:

The balance in the 2023 S&TDA that the Company is proposing to collect from customers is $18.7 million plus interest. The primary driver for the balance in the 2023 S&TDA is higher than forecasted transportation prices, higher than forecasted market-based storage costs in 2023 and a $5.9 million collection from the Union rate zone as part of Enbridge Gas's 2021 Deferral and Variance disposition as approved by the OEB in EB-2022-0110.

The RFP requested offers of storage services with terms of up to 5 years commencing April 1, 2023 with firm injections from May to September and firm withdrawals from December to March.

Question(s):

a) In the 2022 DVA, Enbridge Gas requested offers of storage service with terms of up to 3 years.[1] Please provide a discussion as to why there was an increase in terms up to 3 years to terms up to 5 years.

    i. How has this increase in the length of term benefitted ratepayers?

Response:

a) Since amalgamation, Enbridge Gas has purchased market-based storage through the blind RFP process, for a term of up to five years, to replace storage contracts expiring at the end of the next winter season. The objective is to have a portfolio of storage with diversity of term end dates.

    In 2021, at the time the RFP was issued, the impact of harmonizing storage methodologies on the 2024 rebasing storage requirement was not known. Due to

[1] EB-2023-0092, Exhibit D, Tab 1, p.3.

this uncertainty, Enbridge Gas reduced the maximum term for storage to three years in the 2021 RFP to shift the portfolio towards shorter-term contracts in the event the harmonization of storage methodologies resulted in a storage requirement that was less it had been historically. The change for that year decreased the average term of storage contracts but did not reduce the total amount contracted.

Enbridge Gas returned to the practice of requesting a contract term of up to five years for the 2022 RFP after confirming the 2024 rebasing storage requirements following finalization of the proposal for harmonization of storage methodologies.

i. The change to a three-year storage term for the 2021 RFP benefited ratepayers by ensuring the Company had increased flexibility in 2024 to reduce the amount of contracted market-based storage in the event storage requirements were reduced by harmonization proposals.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

2023 Transactional Services Deferral Account - EGD Exhibit D, Tab 1, p. 3-4

Preamble:

Enbridge Gas generated $59.5 million in net Transactional Services revenue, of which the ratepayer portion represents $53.6 million, through a combination of Storage and Transportation Optimization. The majority of this increase results from the increase in the Dawn-Waddington spread. This spread is impacted by the lack of pipeline infrastructure serving US Northeast markets.

Question(s):

a) Why was Enbridge Gas not able to optimize any storage transactions for the EGD rate zone in 2023.

   i. Does Enbridge Gas expect this trend to continue in 2024?

b) Does Enbridge Gas expect the lack of pipeline infrastructure in Dawn-Waddington spread to continue in 2024?

   i. Are there plans Enbridge Gas knows of to build pipelines to service the Dawn-Waddington spread? If so, what are the timelines?

Response:

a) Enbridge Gas was not able to optimize any storage transactions for the EGD rate zone in 2023 because of reduced demand and value for short term storage services.

   i. Yes, Enbridge expects this trend to continue in 2024.

b) Yes, Enbridge expects the lack of pipeline infrastructure between Dawn-Waddington to continue to impact the related pricing spread in 2024.

   i. Enbridge Gas is not aware of any plans to build pipelines to service the Dawn-Waddington spread.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Unaccounted for Gas Variance Account – EGD Exhibit D, Tab 1, p. 26-28 & Table 1 (p. 6)

Preamble:

Enbridge Gas, in its Phase 1 Rebasing Application, proposed to harmonize UFG related deferral and variance accounts for the EGD and Union Rate Zones into a single UFG Volume Variance Account (UFGVVA). The OEB accepted Enbridge Gas's proposed accounting order and treatment effective January 1, 2024.[1]

Enbridge Gas also undergoes an annual audit of storage inventory to identify inventory variances. In the EGD Rate Zone, Enbridge Gas recovers UFG volumes and costs related to storage operations based on a fixed OEB approved provision, and no variances are recorded in a variance account. Adjustments to inventory from the storage inventory audit in the EGD Rate Zone are not recorded in the UAFVA, which recovers distribution related gas losses only. As a single harmonized UFGVVA was approved as part of Phase 1 Rebasing proceeding, adjustments to inventory resulting from storage inventory audits for both legacy rate zones will be recorded in the UFGVVA as of 2024.

Question(s):

a) Please provide a list of accounts that will be harmonized into the UFGVVA?

   i. Have these accounts been requested for closure? Provide any references.
   ii. If not, why not?

b) Please provide a list of accounts that are approved to be closed in Phase 1 rebasing and proposed to be closed in Phase 2 rebasing, if any. Provide any references.

c) Does Enbridge Gas track, in its EGD rate zone, the adjustments to inventory from the storage inventory audit using any deferral or variance accounts? If so which one?
   i. Please confirm if the storage inventory audits are completed annually.

[1] EB-2022-0200, OEB Decision and Order, December 21, 2023.

ii. If the inventory adjustments are not included in any accounts, what would be the bill impact if the audit adjustments were included in the UFGVA for EGD rate zone?

d) Please provide a table of the UFG sources described in the application, including unknown sources, corresponding to UAF/UFG volumes for each year, as shown in Table 1, for the past 5 years.

Response:

a) The UAF Variance Account (Account No. 179-86) for the EGD Rate Zone and the UFG Volume Variance Account (Account No. 179-135) for the Union Rate Zones will be harmonized into the UFG Volume Variance Account (UFGVVA).

i – ii)

Although these accounts were not formally requested for closure, closure of the accounts as of January 1, 2024 was implicit in the approval to harmonize the accounts as part of the Decision on Settlement dated August 17, 2023.[2] The listing of Accounting Orders that Enbridge Gas proposed effective for January 1, 2024 was approved as part of the Decision on Settlement and then again as part of the Interim Rate Order as approved by the OEB on April 11, 2024[3]. As such, it is Enbridge Gas's understanding that any previous accounts that were effective through 2023 but then approved for harmonization would no longer be effective or in use as of January 1, 2024.

b) In EB-2022-0200, Exhibit 9, Tab 1, Schedule 4, Enbridge Gas proposed the closure of certain deferral and variance accounts. The listing of accounts that were proposed for closure was summarized in Exhibit 9, Tab 1, Schedule 1, Attachment 2. In its Decision and Order dated December 21, 2023[4], the OEB stated: *In the OEB-approved settlement proposal, parties agreed to Enbridge Gas's proposals with respect to the continuation, establishment or closure of many deferral and variance accounts with some agreed to changes.* In that OEB Decision on Settlement Proposal dated August 17, 2023, the settled upon listing of Accounting Orders for Deferral and Variance accounts that are approved as of January 1, 2024 was included in Exhibit O1, Tab 1, Schedule 2, Accounting Orders - Phase 1. Subsequently in its Decision and Order dated December 21, 2023[5], the OEB found that it was: *appropriate to continue the Short-term Storage and Other Balancing Service Deferral Account until the OEB makes a determination on gas storage issues in Phase 2 of this proceeding.* As a result, the following accounts were

[2] EB-2022-0200, Decision on Settlement Proposal, August 17, 2023.
[3] EB-2022-0200, Interim Rate Order, April 11, 2024.
[4] EB-2022-0200, Decision and Order, December 21, 2023.
[5] Ibid.

effectively approved for closure (excluding accounts implicitly closed due to harmonization):

- Transition Impact of Accounting Changes Deferral Account (EGD)
- Ex-Franchise Third Party Billing Services Deferral Account (EGD)
- Renewable Natural Gas Injection Service Variance Account (EGD)
- Dawn Access Cost Deferral Account (EGD)
- Open Bill Revenue Variance Account (EGD)
- OEB Cost Assessment Variance Account (EGD and Union)
- Gas Distribution Access Rule Impact/Costs Deferral Account (EGD and Union)
- Unbundled Services Unauthorized Storage Overrun Deferral Account (Union)
- Capital Pass-through Project Deferral Accounts (Various) (Union)
- Accounting Policy Changes Deferral Account (EGI)
- Impacts Arising from the COVID-19 Emergency Deferral Account (EGI)

c) No. As stated in the Company's pre-filed evidence,[6] the Company recovers UFG volumes and costs relating to storage operations for the EGD Rate Zone (including adjustments relating to the annual storage inventory audit) volumetrically in delivery rates based on a fixed OEB-approved provision established in EGD's 2007 Rate proceeding (EB-2006-0034). No such adjustments or variances relating to storage operations are recorded in any deferral or variance accounts in the EGD rate zone prior to 2024.

i. Confirmed.

ii. As part of the 2024 Rebasing application Phase 1 Settlement[7] a consolidated Enbridge Gas (EGI) forecast of UFG volumes and costs relating to distribution, transmission, and storage was approved and included in the determination of 2024 rates. Variances to the forecast UFG will be recorded in the harmonized EGI UFG Volume Variance Account (UFGVVA). Starting in 2024, adjustments to inventory from the storage inventory audit will be recorded in the UFGVVA for the EGD and Union Rate Zones. However, prior to 2024 in part c), the historic OEB-approved methodology for the recovery of UFG volumes and costs for the EGD Rate Zone relating to storage operations does not include the recording of adjustments relating to the annual storage inventory audit. Accordingly, OEB staff's hypothetical scenario does not reflect how EGD Rate Zone accounts actually operated for 2023. Further, it is not appropriate to consider storage inventory adjustments in isolation as they can be offset by other storage related UFG (volumetric) gains or losses.

[6] EB-2024-0125, Exhibit D, Tab 1, p.28.
[7] EB-2022-0200, Decision on Settlement Proposal, August 17, 2023.

d) A similar question was submitted by OEB Staff as part of the Company's 2022 Deferral and Variance Account Disposition proceedings.[8] In response, the Company explained that at that time (less than 1 year ago) further explanation and/or quantification of contributing sources (root causes) of the 2022 UFG variances were limited. The Company went on to advise that a team was being formed to identify, investigate, and mitigate contributing sources of UFG as well as to develop long-term and sustainable cross-functional governance, monitoring, and reporting.

Since that time, resources were allocated to the UFG team in Q1 2024 and the team set out to address the specific commitments made through settlement negotiations with parties to investigate and report in the current proceeding on the contributing sources of UFG in 2022,[9] with a particular focus on the impacts of:

i. No Bill customers/volumes that are later billed, and

ii. the role of Linepack in transmission and other high-pressure systems in the incidence and determination of UFG.

While Enbridge Gas does not yet possess a comprehensive understanding of all potential sources of UFG or their respective contributions from year-to-year, Table 2 below presents best estimates as of the time of this filing of the historic volumetric impacts of select contributing sources of UFG that have been investigated since the UFG team's formation.[10] As discussed above, the focus of the Company's investigations has been on UFG sources and impacts for calendar year 2022. In this regard, the Company has identified nearly 75% of contributing sources of UFG impacting 2022.

Table 2 also presents best estimates of the historic volumetric impacts of select contributing sources of UFG for 2021 and 2023. The Company's focus has been on 2021 and forward and is therefore not able to provide any further historical estimates of contributing sources of UFG. Enbridge Gas will continue to identify, investigate, and quantify the impacts of additional contributing sources that compose the Unexplained UFG Volumes.

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[8] EB-2023-0092, Exhibit I.STAFF.6 part a).
[9] Please see the response at Exhibit I.ED-1, for detailed references to related settlement negotiations and commitments.
[10] Presented as total Enbridge Gas impacts unless specified otherwise. Please see the response at Exhibit I.MC-1 parts d) & f), for a list summarizing all contributing sources of UFG discussed in the Company's pre-filed evidence categorized according to whether they relate to emissions (physical release from the Company's natural gas systems) or not. Neither the Company's pre-filed evidence, nor the list set out in the response at Exhibit I.MC-1, are considered to be a comprehensive representation of all potential contributing sources of UFG.

The estimates set out in Table 2 reflect the best available information as of August 30, 2024. As discussed in the Company's pre-filed evidence,[11] true-ups and accounting adjustments related to estimation used in both the billing and accounting processes will continue to impact the UFG volumes estimated in Table 2 going forward (i.e., these are known and accepted contributing sources of UFG resulting from standard industry practices). As such true-ups and adjustments are completed the Company expects the remaining Unexplained UFG Volumes associated with 2023 will be significantly diminished (this was the case for both 2021 and 2022).[12] This concept is also discussed in the response at Exhibit I.MC-2 part b), wherein Enbridge Gas explains that accounting and billing processes (along with measurement uncertainty and fluctuations in customer demand) contribute to UFG variation from year to year. Importantly, the Company goes on to explain that accounting and billing processes (e.g., meter estimates, cycle billing, and No-Bills) are contributing sources of UFG that are correlated from year to year.[13]

As discussed in the Company's pre-filed evidence and responses to interrogatories,[14] in all instances set out in Table 2 it is important to consider the relative range of uncertainty associated with estimated volumetric impacts (e.g., the accuracy of measurement assets, estimated emissions, etc.) when evaluating the magnitude of impacts to UFG.

Enbridge Gas has included estimates for Gate Station Measurement Variation and Residential Meter Variation at lines 7 and 10 of Table 2 as these are known and accepted contributing sources of UFG.[15] To determine these estimates, Enbridge Gas used the same methodology applied by ScottMadden in its Report on Unaccounted for Gas.[16] As discussed in the Company's pre-filed evidence,[17] Enbridge Gas operates within more stringent internal measurement error tolerances than those established by Measurement Canada.

[11] Exhibit D, Tab 1, pp. 16-28.
[12] See volumes set out in lines 1-4 of Table 2.
[13] Meaning that when such sources drive lower reported Consumption levels at the end of one year, UFG will increase (the opposite is true with respect to Sendout related contributing sources). Consequently, UFG levels in the following year would be expected to be suppressed (or increased with respect to Sendout related contributing sources).
[14] Exhibit D, Tab 1, p. 8. Exhibit I.ED-10 part b).
[15] Gate Station Measurement Variation and Residential Meter Variation are known baseline UFG contributors included in the Report on UFG discussed at Exhibit D, Tab 1, p. 10.
[16] 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
[17] As described at Exhibit D, Tab 1, pp. 15-16, Enbridge Gas maintains its metering calibration within a +/- 1% internal standard measurement error tolerance as compared to Measurement Canada's +/- 3% overall volume measurement error tolerance. As discussed in the ScottMadden Report on Unaccounted For Gas at EB-2019-0194, Report on UFG, December 19, 2019, pp. 30-33 & 35-38, both Union and EGD maintained calibration standards well below 1% over a 5 year average in both the high flow scenario (e.g., retail measurement: Union 0.12%, EGD -0.02%) and low flow scenario (e.g., retail measurement: Union 0.58%, EGD 0.41%).

Fugitive emissions-related volumes are presented separately in Table 2. As discussed in the responses at Exhibit I.FRPO-17 and at Exhibit I.MC-1, 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. Initiatives discussed in the Company's pre-filed evidence related to physical gas losses (i.e., Work to Update a Backlog of Leaks, Loss of Containment, Operational Emissions Reductions) are included within Emissions Related Estimates values in Table 2.

Not included in Table 2 are additional contributing sources of UFG discussed within Enbridge Gas's pre-filed evidence for which no estimate of their respective impacts currently exists. Examples include (but are not limited to) vacant premises backlog, pressure elevation factors and power customer measurement. These additional contributing sources compose some portion of the Unexplained UFG Volumes noted in line 15 of Table 2.

Enbridge Gas also provides a summary of conclusions drawn from its interpretation of the estimates set out in Table 2.

Table 2
Estimated Enbridge Gas Contributing Sources of UFG (10^3m^3)

Line No.	Particulars	Notes	(a) 2023	(b) 2022	(c) 2021
Non-Emissions Related Estimates					
	Correlated Non-Emissions Related Estimates				
1	Gas Accounting Adjustments	(1)	429	5,022	(5,239)
2	Other Prior Period Billing Adjustments	(2)	(81,277)	109,070	(77,389)
3	Unbilled Estimates	(3) (4)	(14,093)	12,891	4,166
4	No-Bills Estimates	(5) (6)	(25,755)	27,405	23,740
5	Minimum Linepack	(7)	858	(202)	(2,045)
6	Operational Linepack	(8)	82	-	-
7	Residential Meter Variation	(11)	24,978	66,209	43,804
	Un-Correlated Non-Emissions Related Estimates				
8	Work to Update Gas Quality Parameters	(9)	2,116	2,116	2,116
9	Storage Inventory Audits and Adjustments	(10)	(4,853)	2,834	2,601
10	Gate Station Measurement Variation	(11)	36,367	112,788	55,497
11	***Total Non-Emissions Related Estimates***	(12)	***(61,149)***	***338,134***	***47,250***
Emissions Related Estimates					
12	Fugitive Emissions Inventory	(13)	22,624	34,398	28,004
13	***Total Emissions Related Estimates***		***22,624***	***34,398***	***28,004***
14	***Enbridge Gas Total Annual UFG Volumes***	(14)	***201,845***	***507,025***	***368,136***
15	***Unexplained UFG Volumes***	(15)	***240,370***	***134,493***	***292,882***

NOTES:
(1) Specific to Union Rate Zones due to differences in historic UFG/UAF accounting treatment.
(2) Prior period billing adjustments relating to an applied year/month in a previous fiscal year unrelated to No-Bills and Unbilled estimates. Reflects adjustments known as of August 30, 2024.
(3) True-up impacts relating to December Unbilled estimate in the previous year + December Unbilled estimate in the current year. Please see Exhibit D, Tab 1, Section 1.3, pp. 18-23 for further discussion.
(4) Unbilled estimate impact relating to 2021 is approximate as December 2020 impact on 2021 rounded to the nearest 1,000 10^3m^3 per EB-2022-0110, Exhibit I.STAFF-11 part c).
(5) Please see Exhibit D, Tab 1, Section 2, p. 47, Table 8. The No Bills estimate for 2023 has been updated to reflect adjustments known as of August 30, 2024.
(6) As the impacts of No-bills estimates for the EGD Rate Zone have been trued-up, the impacts in line 4 are limited to those of the Union Rate Zones.
(7) Please see Exhibit D, Tab 1, Section 3.1, Table 9, p. 52, for detail on Minimum Linepack adjustments.
(8) Please see the response at Exhibit I.FRPO-31 part a).
(9) Please see Exhibit D, Tab 1, Section 1.4, p. 30. Impacts are estimated at 2022 historic levels for representative order of magnitude purposes only.
(10) Please see Exhibit D, Tab 1, Section 1.4, p. 37, Table 6. Only the Union Rate Zones specific storage adjustment impacts have been identified. Each impact has the opposite effect on UFG levels to the adjustment made in the UFGVVA.
(11) Estimates for measurement variation are based on the proration identified in the ScottMadden Report on Unaccounted for Gas, wherein UFG resulting from measurement variation is calculated as a percentage of total annual UFG volumes from the 10-year average. EB-2019-0194, Report on UFG, December 19, 2019, pp. 6-7; https://www.rds.oeb.ca/CMWebDrawer/Record/664529/File/document.
(12) Calculated as the sum of lines 1-11.
(13) 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. Loss of containment and the backlog of leaks discussed in the Company's pre-filed evidence are included in these fugitive emissions volumes.
(14) The sum of UAF/UFG from Exhibit D, Tab 1, p. 6, Table 1 and Exhibit E, Tab 1, p. 27, Table 2.
(15) Calculated as the difference between line 14 and the sum of lines 11 + 13.

Based on the estimates set out in Table 2, Enbridge Gas has drawn the following conclusions:

- Comparing emissions related estimated volumes (line 13) to non-emissions related estimated volumes (line 11), it is important to recognize that in all years the impacts of non-emissions related contributing sources significantly exceed those associated with fugitive emissions (that result from the unintended physical release of gases from equipment leaks and third-party damage events).

- Although accounting and billing-related contributing sources (lines 1-4) vary from year-to-year, they are common throughout the natural gas utility industry and the net impact to UFG of these figures over the course of 2021 to 2023 is currently estimated at -21,030 10^3m^3.[18] This supports the Company's previous conclusions, as discussed above and articulated in the response at Exhibit I.FRPO-27, that accounting and billing-related contributing sources (including billing based on estimated volumes) do not contribute to UFG in the long-term. Instead, they contribute to increased UFG volatility in the short-term due to accounting/billing adjustments which are applied in the current fiscal year for a period already billed in a previous year.

- Impacts of billing estimates (lines 2-4) on UFG is an unavoidable contributing source of UFG absent access to real-time/instantaneous customer consumption data (e.g., via AMI).

- Identified contributing sources that can be attributed to specific (uncorrelated) events (lines 8-9) have been correctly accounted for by making adjustments in the fiscal year they become known and quantified. Further, estimated volumes attributable to these sources are not significant contributors to total annual UFG volumes for the period from 2021 to 2023.

- The impacts of measurement uncertainty (lines 7 and 10) are unavoidable and Enbridge Gas has taken reasonable measures to refine and remediate such impacts, far exceeding Measurement Canada guidelines.

[18] A negative UFG volume in this context denotes net suppression of UFG volumes from 2021-2023 resulting from the effect of aggregated impacts from all accounting and billing processes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Highwood Recommendations and Fugitive Emissions Measurement Administration Deferral Account (FEMADA) Exhibit D, Tab 1, p. 60-67 & Attachment 1

Preamble:

Highwood recommended the development of company-specific emission factors for distribution operations, prioritizing sources with high materiality and high levels of uncertainty and piloting a Mobile Ground Detection (vehicle) measurement strategy.

Enbridge Gas has assessed the causation, materiality, and prudence of the FEMADA Deferral Account. For materiality, Enbridge Gas's forecasted spend exceeds the $1 million materiality threshold for the establishment of a new account. As detailed in Table 12, the Company is forecasting to spend approximately $2.6 million in FEMADA administration and pilot costs in 2025.

Enbridge Gas anticipates the incremental costs associated with the pilot program to be $1.7 million. The mobile ground pilot program will require designing study parameters, deploying a mobile technology, validating and comparing performance of the technology against known methods, and conducting follow-up investigations by foot to locate and confirm leaking components. Incremental management and repair of leaks located during this pilot are not included in this cost estimate as they would be covered by the existing integrity programs.

Question(s):

a) Does Enbridge Gas have plans to develop company-specific emissions factors beyond piloting the Mobile Ground Detection? If yes, please provide the plan and timelines.

b) Enbridge Gas's Z-factor materiality threshold was set at $5.5 million[3], and the company has not requested to change in its Phase 2 rebasing application.[4]

    i. Please confirm whether Enbridge Gas's materiality threshold is $1 million or $5.5 million.

ii. If Enbridge believes the materiality threshold should be set to $1 million, explain why it should not use the Z-factor threshold of $5.5 million.

iii. If Enbridge believes the materiality threshold is $5.5 million does the FEMADA still need to be established as it is under the Z-factor threshold?

c) If Enbridge Gas receives the approval to establish the FEMADA, what other approvals are required for Enbridge Gas to proceed with the pilot program?

d) Please confirm that Enbridge Gas has a Leak Survey department equipped with leak/ methane detection devices (handheld devices and vehicles)

i. How does the Mobile Ground Detection vehicle differ from Enbridge Gas's current leak survey vehicles?

ii. Is Enbridge Gas able to utilize internal leak survey data to develop its emissions factors?

e) Has Enbridge Gas explored similar detection technology as part of its R&D program? If so, please provide a list of technology on leak detection that is currently being used, currently being proposed, and technology that has been previously explored and a description of the differences among the technologies.

<u>Response:</u>

a) As outlined in the Company's pre-filed evidence,[1] Enbridge Gas plans to develop company-specific emission factors on a subset of distribution assets, in addition to piloting a mobile ground detection technology. Please see the response at Exhibit-I.ED-12 for estimated timelines for the Company's proposed Fugitive Emissions Investigation Plan.

b)

i. and ii.

Enbridge Gas confirms that it has not requested a change to the materiality threshold ($5.5 million) in relation to Z-factor treatment for specific material changes in costs associated with unforeseen events outside of the control of management.

However, the materiality threshold applicable for Z-factor treatment is not what is required by the OEB for the establishment of deferral and variance accounts. The OEB Filing Requirements for Natural Gas Rate Applications require a new D&VA request be accompanied by evidence on how the eligibility criteria will be met in

[1] Exhibit D, Tab 1, pp.62-63.

relation to materiality: 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. 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.[2]

iii. Enbridge Gas notes that the proposed FEMADA is appropriate to be established as it meets the criteria for establishment of a deferral or variance account. It does not regard the costs that are expected to be incurred as resulting from Z-factor considerations.

c) Enbridge Gas does not anticipate that additional approvals, beyond the approval of the FEMADA, will be required to proceed with the pilot program.

d) Enbridge Gas currently administers annual leak survey programs for storage and transmission operations (STO) and distribution operations (DO), in compliance with applicable regulatory requirements. Surveys are generally conducted by third party contractors, using a combination of handheld and vehicle technologies. Enbridge Gas also owns handheld devices and vehicles, which are used by Operations to locate detected leaks and confirm repairs.

i. The vehicles that are currently used for leak surveys measure methane concentration (ppm) in the atmosphere and are used to detect the presence of leaks. In order to quantify methane emissions, the use of a vehicle technology capable of providing leak flow rate (kg/hr) is required.

ii. STO leak surveys of compressor stations and meter/receipt stations are performed by third party contractors. These surveys include the use of optical gas imaging (OGI) to detect leaks and hi-flow sampling to obtain leak flow rate. Leak rate information from these surveys is used for annual STO emissions reporting.[3]

Current EGI DO leak surveys do not include measurement of leak flow rates and therefore current leak survey data cannot be used to develop emission factors for distribution assets.

e) Enbridge Gas has previously piloted technologies for leak detection applications (i.e., finding leaks). However, the Company has not evaluated technologies for emissions measurement applications which quantify leak flow rate.

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[2] OEB Filing Requirements for Natural Gas Rate Applications, February 16, 2017, p.38.
[3] Exhibit D, Tab 1, Attachment 1, Table 16, p.49.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 75-78

Preamble:

The balance in this deferral account is a credit to the EGD Rate Zone of $4.909 million plus interest of $0.232 million for a total credit balance of $5.141 million.

Question(s):

a) Explain why the NPS 20 Don River Replacement Project had a forecast of $0 in the Phase 1 Rebasing Settlement Proposal.

    i. Did parties know there was potentially a balance for this project/ line item? Please provide a reference if applicable

b) Please provide lists of all ICM projects that can be included in this account in 2023 and 2024.

Response:

a) In the 2024 Phase 1 Rebasing application, Enbridge Gas provided a forecast balance for the Don River Replacement Project.[1] The cumulative forecast at that time was a balance that rounded to nil.

    i. As provided in the 2024 Phase 1 Rebasing application, Enbridge Gas noted:

> As the final balances are not known at this time for all the accounts, Enbridge Gas is proposing disposition on an interim basis. Enbridge Gas will seek final disposition of the D&VA balances, calculated as the difference between actual balances as of December 31, 2023, and balances approved for disposition as part of this Application, within the

[1] EB-2022-0200, Exhibit 9, Tab 2, Schedule 1, Attachment 6.

Company's 2023 annual earnings sharing and D&VA disposition proceeding.[2]

Therefore, parties were made aware that there was potentially a balance for this project among other balances.

b) The list of ICM projects applicable to the EGD Rate Zone in 2023 were included in Exhibit D, Tab 1, page 76 of 79. This list is reproduced below:

- NPS 20 Don River Replacement Project
- NPS 20 Cherry to Bathurst Replacement Project

As part of Enbridge Gas's 2024 Phase 1 Rebasing application (EB-2022-0200), the revenue requirement impacts of the above noted projects were reflected in 2024 base rates, ending the need for ICM treatment. In addition, also as part of that proceeding, the Union Rate Zones ICM Deferral Account and EGD Rate Zone ICM Deferral Account were harmonized into a single Enbridge Gas ICM Deferral Account commencing in 2024. There are no approved ICM projects for 2024.

[2] EB-2022-0200, Exhibit 9, Tab 2, Schedule 1, pp.1-2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Renewable Natural Gas (RNG) Injection Service Variance Account - EGD Exhibit C, Tab 1, p. 77-78

Preamble:

Enbridge Gas is seeking final disposition of the total balance in the RNGISVA which is a cumulative credit to ratepayers of $0.332 million plus interest of $0.029 million, for a total credit balance of $0.360 million.

Question(s):

a) Please confirm this is the first time Enbridge Gas seeks to dispose of this account.

b) Does Enbridge Gas expect the revenue requirement for Dufferin injection to increase into 2024?

Response:

a) Confirmed. This is the first (and only) time Enbridge Gas seeks to dispose of this account. As noted in the 2024 Rebasing Phase1 application:

> Enbridge Gas is proposing to include the cost to provide the RNG Injection Service in the 2024 Test Year revenue requirement and the fixed revenue of the service in the 2024 revenue forecast. As a result, any variances between fixed rate charged to customers and the costs to provide the service will be recovered through the cost of service process. This approach is consistent with OEB Staff's comments from the RNG Enabling Program proceeding, which were that an RNG facility project is no different from any other natural gas expansion project where Enbridge Gas would recover the costs over the lifespan of the project and where annual true-ups are not performed.[1]

And

[1] EB-2022-0200, Exhibit 9, Tab 1, Schedule 4, p.3

Under the proposed process, the RNGISDA is no longer required. Enbridge Gas is proposing to close the RNGISDA effective January 1, 2024 as part of this Application. Disposition of cumulative deferral account balances to December 31, 2023, will be requested for disposal with the Company's 2023 Earnings Sharing and Deferrals Disposition Application as provided at Exhibit 9, Tab 2, Schedule 1.[2]

b) Enbridge Gas expects an immaterial increase to the 2024 revenue requirement related to Dufferin injection service, and from there expects annual decreases in revenue requirement over the life of the assets as the required return on investment decreases annually.

[2] EB-2022-0200, Exhibit 9, Tab 1, Schedule 4, p.4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Unabsorbed Demand Costs Variance Account (UDCVA)- Union Gas Exhibit E, Tab 1, p. 1-5

Preamble:

The UDCVA balance is the difference between the actual UDC incurred by the Union rate zones and the amount of UDC collected in rates, partially offset by a credit to ratepayers related to a refund of Panhandle Pipeline tolls that were applicable to UDC costs between 2020 and 2023.

Enbridge Gas received a refund from Panhandle Pipelines regarding over-recovery of costs of service of which $2.24 million, including interest, pertained to UDC between 2020 and 2023. This amount has been credited to the appropriate rate zones in alignment with the historic allocation of UDC costs for each year.

Question(s):

a) Please provide the allocation that was used to collect the Panhandle Pipeline tolls.

   i. Is the allocation the same as the historic allocation of UDC costs for each year?

   ii. If they are not the same allocation, please explain why Enbridge would propose to use a different allocation to the one that was used to collect the tolls.

Response:

a) Please see Table 1 for the allocation of the Panhandle Pipeline tolls related to unabsorbed demand charges (UDC) for the years 2020 to 2023.

Table 1
UDC Impact of Panhandle Pipelines Toll Update

Line No.	Particulars ($000s)	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	2020	(253)	(262)	(365)	(880)
2	2021	(1)	(1)	(1)	(3)
3	2022	(4)	(380)	(108)	(492)
4	2023	(73)	(356)	(231)	(660)
5	Interest	(34)	(101)	(72)	(206)
6	Panhandle Pipelines Refund Impact, including interest	(364)	(1,100)	(778)	(2,241)

i. Yes.

ii. Please see subpart i.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Unaccounted for Gas Volume Deferral Account (UFGVDA)- Union Gas Exhibit E, Tab 1, p. 25

Preamble:

Based on 2023 actual throughput volumes, Enbridge Gas recovered $16.4 million in UFG costs through rates. Enbridge Gas's actual 2023 UFG costs were $20.3 million. The variance between 2023 UFG costs recovered through rates and actual 2023 UFG costs is $3.9 million, which is below the $5.0 million dead band established by the OEB for the UFGVDA. As a result, there is no 2023 balance in the UFGVDA.

Question(s):

In the 2022 DVA, Enbridge Gas's actual UFG cost was $65.8 million. Please explain why there was a precipitous drop in UFG costs between 2022 ($65.8 million) and 2023 ($20.3 million).

Response:

The reduction in 2023 UFG cost relative to 2022 of $45.5 million is driven by lower commodity cost in 2023 for approximately $25.6 million, and lower UFG volumes in 2023, as shown at Exhibit E, Tab 1, page 27, Table 2, for approximately $19.9 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Unaccounted for Gas Price Deferral Account- Union Gas Exhibit E, Tab 1, p. 30-32

Preamble:

During 2023, the Enbridge Gas purchased 25,047 103m3 of gas supply in Union rate zones related to actual UFG volumes on behalf of ratepayers.

The average actual cost of the UFG purchases in 2023 is \$25.12/103m^3 lower than the OEB-approved reference prices included in rates based on the Union South rate zone gas portfolio cost of \$179.35/10^{3}m^3. The result is a \$0.63 million balance to be refunded to ratepayers. Table 2 states that the average price was \$154.24/103m^3.

Question(s):

In the 2022 DVA, Enbridge Gas's actual average cost of the UFG purchase was \$327.49/103m^3.[6] Please explain why there was a precipitous drop in the actual average cost of the UFG purchases between 2022 (\$327.49/103m^3) and 2023 (\$154.24/103m^3).

Response:

The drop in the 2023 actual average cost relative to 2022 is driven by the lower gas supply commodity costs in 2023 versus 2022. The lower gas supply commodity costs are demonstrated in the lower OEB-approved reference prices in 2023 as shown in Table 2 of Exhibit E, Tab 1, page 32, line 1, in comparison to the 2022 OEB-approved reference prices in the 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding at EB-2023-0092 Exhibit E, Tab 1, page 48, line 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Incremental Capital Module Deferral Account – Union Gas Exhibit E, Tab 1, p. 52

Preamble:

The balance in this deferral account is a credit to the Union Gas Rate Zone of $0.384 million plus interest of $0.504 million for a total credit balance of $0.888 million.

Question(s):

Please provide lists of all ICM projects that can be included in this account in 2023 and 2024.

Response:

The list of ICM projects applicable to the Union Rate Zone in 2023 were included in Exhibit E, Tab 1, Table 1, page 54 of 55. This list is reproduced below:

- Kingsville Transmission Reinforcement Project
- Windsor Line Replacement Project
- London Lines Replacement Project

As part of Enbridge Gas's 2024 Phase 1 Rebasing application,[1] the revenue requirement impacts of the above noted projects were reflected in 2024 base rates, ending the need for ICM treatment. In addition, also as part of that proceeding, the Union Rate Zones ICM Deferral Account and EGD Rate Zone ICM Deferral Account were harmonized into a single Enbridge Gas ICM Deferral Account commencing in 2024. There are no approved ICM projects for 2024.

[1] EB-2022-0200.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Scorecard Cover letter, May 31, 2024
Exhibit G, Tab 1

Preamble:

Enbridge Gas provided the Scorecard and the Indigenous Working Group Report. No approval is being sought regarding these items.

Enbridge Gas was able to significantly decrease the number of meters with consecutive estimates and reached an annual MRPM of 4.1% in 2022 and 1.3% in 2023. Despite improving this metric, there are persisting challenges beyond Enbridge Gas' control that limit the ability for meter readers to access and read a certain portion of gas meters, impairing the ability to achieve this target.

Question(s):

a) Please confirm that the scorecard issues are being addressed in Phase 2 of Enbridge Gas's rebasing.

b) Provide additional discussion on the challenges that "are beyond Enbridge Gas's control" that limit access and read the gas meters?

    i. Are there additional plans in place to further reduce the annual MRPM to the target level?

Response:

In response to the preamble to this question, Enbridge Gas wishes to highlight that it is seeking "review or approval" of the proposed Indigenous Working Group (IWG) budget for 2025, as contemplated at page 18 of the EB-2022-0200 Settlement Proposal. Enbridge Gas is seeking to have parties and/or the OEB approve, endorse or indicate non-opposition to the proposed IWG budget for 2025 as part of either a Settlement Proposal or, if necessary, a hearing process.

a) Confirmed. Meter Reading Performance Measurement (MRPM) is being addressed in Rebasing Phase 2 (EB-2024-0111).

b) Enbridge Gas has provided evidence which describes the challenges that are beyond Enbridge Gas's control. Please see evidence provided at Rebasing Phase 2, Exhibit 1.7.1, Section 2.3, pages 10 – 13.

    i. Please see the mitigation measures Enbridge Gas has outlined in Rebasing Phase 2, Exhibit 1.7.1, Section 3, pages 13 - 18. Enbridge Gas's ability to reduce the annual MRPM to the target level is further detailed at, Rebasing Phase 2, Exhibit 1.7.1, Section 2.2, page 9, paragraph 24.

PENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Indigenous Working Group (IWG) Report Cover letter, May 31, 2024
Exhibit G, Tab 1

Preamble:

Enbridge Gas provided the Scorecard and the Indigenous Working Group Report. No approval is being sought regarding these items.

In the IWG report, it stated under the Settlement Proposal, Enbridge Gas was required to provide capacity funding. Enbridge Gas presented the 2025 estimated budget for review by the OEB as part of the DVA proceeding. The Indigenous Parties propose the following budget for capacity funding for 2025 of $800,000.

Question(s):

a) Please confirm that Enbridge Gas is not seeking approval for the budget for capacity funding for 2025 in this proceeding.

b) Where does the funding for the IWG come from?

Response:

a) Enbridge Gas is seeking “review or approval” of the proposed Indigenous Working Group (IWG) budget for 2025, as contemplated at page 18 of the 2024 Phase 1 Rebasing Settlement Agreement[1]. Enbridge Gas is seeking to have parties and/or the OEB approve, endorse or indicate non-opposition to the proposed IWG budget for 2025 as part of either a Settlement Proposal or, if necessary, a hearing process.

b) In accordance with the OEB approved 2024 Phase 1 Rebasing Settlement Agreement, Enbridge Gas has established an IWG deferral account (IWGDA) to record the actual Capacity funding costs.[2] Such amounts will be subject to review and clearance in the applicable DVA proceeding, the first of which will be in 2025, relating to cost incurred to the end of 2024.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2021, pg.18.
[2] Ibid.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex.B/T3/S2/p. 9
EB-2024-0111/Ex. I.1.13-SEC-10
EB-2024-0111/Ex. I.1.13-FRPO-10

Question(s):

a) Please explain why the Dawn to Corunna project is considered a compressor station asset. As part of this response, please advise whether the “Compression Station” asset class described at Exhibit B, Tab 3, Schedule 2, page 9 is the same as the “Compressor Equipment (456)” asset class shown at EB-2024-0111, Exhibit I.1.13-FRPO-10.

b) For each regulated project (both EGD and Union rate zones) with a cost greater than $2 million that is described at Exhibit B, Tab 3, Schedule 2, pages 9-11, please advise at which line in EB-2024-0111, Exhibit I.1.13-SEC-10 (Tables 2 and 3) the project is shown. As part of this response, please explain any variances in projects costs provided between the two applications.

c) For each project (both regulated and unregulated and both EGD and Union rate zones) described at Exhibit B, Tab 3, Schedule 2, pages 9-11, please provide the allocation between regulated and unregulated storage. As part of the response, please explain the allocation methodology applied. As an example, for the “Dawn:5985 CV Piping & Improvements” project, please explain how much of the project cost was allocated to each of the regulated and unregulated businesses and explain how it was allocated.

Response:

a) The Dawn to Corunna project was deemed a compressor station asset because it replaced the compressors retired at the Corunna Site and the function they provided. The project was classified based on need and not the alternatives considered. “Compression Station” is the asset class in the Asset Management Plan. “Compressor Equipment (456)” refers to the depreciable plant account. For example, a $2.0 million project that belongs to the Compression Station asset class could result in multiple assets, such as a $1.5 million Compressor Equipment (456) and $0.5 million Field Lines (455).

b) and c)

The costs presented at Exhibit B, Tab 3, Schedule 2 represent 2023 capital expenditures. The costs presented in EB-2024-0111, Exhibit I.1.13-SEC-10 represent total project costs, which include expenditures in years prior to 2023. Another difference is due to having only storage projects which are subject to the storage cost allocation methodology being included in EB-2024-0111, Exhibit I.1.13-SEC-10. The projects which are part of Exhibit B, Tab 3, Schedule 2, pages 9-11, include all projects within the Compression Stations and Transmission Pipe & Underground Storage Asset Classes including transmission projects. Please see Attachment 1 for further details.

Line #	Sec 10 Line #	Project Name	Regulated/ Unregulated	2023 ESM	Exhibit I 1.13 Sec 10	Variance (E-F)	Variance Explanation	Allocation Methodology
1	27	Dawn To Corunna Replacement (EGD & UG)	Regulated	303.2	342.5	(39.3)	SEC-10 includes prior years spend	Maintained existing allocation
2	29	SCOR:60004-Fdn-Blk-Replace	Regulated	3.0	4.7	(1.7)	SEC-10 includes prior years spend	Maintained existing allocation
3	-	SSOM:K-802 ISO Valves -Replace	Regulated	1.1	-	1.1	Under $2M reporting threshold	Maintained existing allocation
4	-	SSOM: V-0805 ISO Valves - Rep	Regulated	1.0	-	1.0	Under $2M reporting threshold	Maintained existing allocation
5	-	SCOR:61008 Top End-O/H	Regulated	1.0	-	1.0	Under $2M reporting threshold	
6	30	NPS 16 Wilkesport P and C	Regulated	2.9	2.8	0.1	Rounding difference	Maintained existing allocation
7	28	NPS 16 WLK Trans Retrofit	Regulated	1.8	3.2	(1.4)	SEC-10 includes prior years spend	Maintained existing allocation
8	-	PCRW: Wells-Upgrade	Regulated	1.5	-	1.5	Under $2M reporting threshold	Maintained existing allocation
9	-	NPS 20 SK Loop P&C	Regulated	1.0	-	1.0	Under $2M reporting threshold	Maintained existing allocation
10	-	Dow Moore MOP Remediation	Regulated	1.0	-	1.0	Under $2M reporting threshold	Maintained existing allocation
11	-	TPS-Wells SE24 PMKC	Unregulated	1.7	-	1.7	Under $2M reporting threshold	Increase Storage capacity/deliverability
12	-	LLAD:Pipeline and Meter Station	Unregulated	1.4	-	1.4	Under $2M reporting threshold	Increase Storage capacity/deliverability
13	-	SE 21/22 LDOW	Unregulated	1.2	-	1.2	Under $2M reporting threshold	Increase Storage capacity/deliverability
14	-	PLAD:TL8 A1 Obs Well-Drill	Unregulated	1.1	-	1.1	Under $2M reporting threshold	Increase Storage capacity/deliverability
15	7	Dawn:5985 CV Piping & Improvements	Regulated	3.3	3.6	(0.3)	The ESM evidence referenced the Dawn Dehy Plant -	Maintained existing allocation
16	7	~~Dawn Dehy Plant - Process Tank Replacement~~ Dawn:5985 CV Piping & Improvements	Unregulated	5.9	5.1	0.8	Process Tank Replacement, which was the incorrect project name, and should have been the Dawn: 5985 CV Piping & Improvements project. The $3.3M and $5.9M in the ESM commentary below Table 4-5 on page 10 paragraph 8 included cost of retirement, which was incorrect, as the costs are not part Table 4-5 and not in Exhibit I 1.13 SEC 10.	Increase Storage capacity/deliverability
17	-	STO Convert High Bleed devices to Low/no bleed	Regulated	2.1	-	2.1	ESM includes Transmission projects, not in SEC-10.	Maintained existing allocation
18	-	Bright B PLC Upgrade	Regulated	1.2	-	1.2	Under $2M and includes Transmission projects in ESM but not in SEC-10.	Storage allocation not applicable for transmission projects
19	-	Dawn I Plant Glycol Line Replacement	Unregulated	0.9	-	0.9	Under $2M reporting threshold	Maintained existing allocation
20	-	Panhandle Regional Expansion Project	Regulated	50.1	-	50.1	ESM includes Transmission projects, not in SEC-10.	Storage allocation not applicable for transmission projects
21	-	Trafalgar NPS 26 Integrity Digs	Regulated	7.4	-	7.4	ESM includes Transmission projects, not in SEC-10.	Storage allocation not applicable for transmission projects
22	-	Panhandle NPS 20 AC Mitigation	Regulated	4.9	-	4.9	ESM includes Transmission projects, not in SEC-10.	Storage allocation not applicable for transmission projects
23	-	Dawn-Cuthbert - NPS 42 replacement	Regulated	1.1	-	1.1	Under $2M and includes Transmission projects in ESM but not in SEC-10.	Storage allocation not applicable for transmission projects
24	-	Trafalgar NPS 26 Line Lowering	Regulated	1.9	-	1.9	Under $2M and includes Transmission projects in ESM but not in SEC-10.	Storage allocation not applicable for transmission projects
25	-	NPS 20 Bickford Sombra IFK Repairs	Regulated	1.0	-	1.0	Under $2M reporting threshold	Maintained existing allocation
26		SE21/22-NPS24/Tie in/STN, Mandaumin A1 observation well and Bluewater A1 Well	Unregulated	2.7	-	2.7	Individual projects under $2M	Increase Storage capacity/deliverability
				405.4	361.9	43.6		

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex.C/T1/p. 15
EB-2023-0093/Ex.C/T1/pp.16-19

Question(s):

Please explain the increase in incremental FTE costs from $1.77M (2022) to $2.68M (2023). As part of the response, please provide a breakdown of the cost increase due to FTE count increases and due to salary/benefit escalation.

Response:

The breakdown of the cost increase due to FTE count increases (2.5 FTE count increase) cannot be broken out of the total incremental FTE costs as it would provide for the ability to discern personal salary information due to the low number of FTEs.

Please see the response at Exhibit I.FRPO-13 for additional details on the FTE cost increase between 2022 and 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex.C/T1/pp. 24-28

Question(s):

a) Prior to the 2022 renewal of unionized labour contracts, please advise when those contracts were most recently renewed.

b) Please discuss why Enbridge Gas is of the view that the entirety of the unionized wage increase resulting from the renewed labour contracts is directly attributable to Bill 93.

c) With respect to the establishment of base 2023 locate and VMS costs, please explain why Enbridge Gas is escalating 2021 actual costs using the PCI instead of unadjusted inflation percentages (with no reduction for the stretch factor).

d) Please provide the actual locate volumes for: (i) January-March 2023; and (ii) April-December 2023.

e) Please provide the actual VMS hours for: (i) January-March 2023; and (ii) April-December 2023.

Response:

a) These unionized workers are not employees of Enbridge Gas. Locate Service Providers (LSPs) have last negotiated contracts with various LiUNA locals in 2018, 2019, and 2020.

b) Enbridge Gas believes that the documented increase in the cost per locate, above the accounted for OEB approved Price Cap Index (PCI) is the result of Bill 93 and its associated regulations. The 5 day locating requirement created the need to attract and retain locating professionals, which was not possible with the wages offered in previous labour contracts. Bill 93 resulted in the locating industry recognizing locators as professional skilled labour similar to other skilled labour (ex. construction, road builders, etc.) resulting in a significant increase in locate costs, far greater than PCI inflation, for Enbridge Gas.

c) Enbridge Gas escalated 2021 actual locate and VMS costs by PCI, as opposed to unadjusted inflation percentages, in order to establish a base 2023 amount presumed/expected to be recovered through rates, absent the impacts of Bill 93. PCI was utilized as opposed to unadjusted inflation percentages because that is what the base amount in rates was escalated by. The 2021 actual costs were used as the starting point because they reflected a base level of costs before any impacts of Bill 93 were realized, and because it recognized that actual incurred locate costs in advance of Bill 93 were already higher than the actual escalated amount embedded in base rates, and that those increased costs were not recoverable through the GOCVA.[1]

d) Locates for January-March and April-Dec 2023 are 169,168 and 806,721 respectively.

e) Actual VMS hours for January-March and April-Dec 2023 are 8,443 and 48,603 respectively.

[1] Exhibit C, Tab 1, p.26, para.12.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex.D/T1/pp. 33-34, 40, 43-44, 61-66
Ex.D/T1/Schedule 3

Question(s):

a) In the context of a vacant premise whereby a new customer eventually does establish a customer account (but gas was consumed prior to the new account being established), is that new customer responsible for paying for all unbilled gas that was consumed? If not, please explain. If yes, please explain how that billed gas is treated in the UAFVA.

b) Please advise whether Enbridge Gas currently applies pressure elevation factors to customers' bills. If so, is the initiative described at Exhibit D, Tab 1, page 40 seeking to recalibrate those elevation factors for greater accuracy?

c) Please advise whether Line 12 (Damage Adjustment) of Exhibit D, Tab 1, Schedule 3 reflects recoveries from third-parties who damaged Enbridge Gas's facilities in the EGD Rate Zone.

d) Enbridge Gas stated that, "while the measurement facilities originally designed and installed by Enbridge Gas for these customers continue to measure accurately under their original high load factor conditions, they do not measure Consumption accurately under low-flow conditions (i.e., when turbines are not running)."

   Please confirm that this means that gas consumption used for space heating, water heating, etc., at these facilities may be unbilled to these customers.

e) Please further explain the basis of the leak volume estimate of 18,118 10^3m^3. As part of this response, please provide the relative contribution to the leak volume estimate between DO and STO.

f) Based on the uncertainty ranges related to fugitive emissions (i.e., <10% for STO and >115% for DO), please provide a range of minimum and maximum leak volumes.

g) Assuming the leak volume estimate (i.e., 18,118 10^3m^3) is accurate, please confirm, or otherwise correct, that the value in terms of reduced UFG costs of eliminating all leaks would be approximately \$3 million (using the July 2024 EGD PGVA reference price of approximately \$168/$103m^3$). Would there also be reductions in carbon charges borne by customers? If so, please quantify the value of those savings.

h) Enbridge Gas forecast incremental costs related to its fugitive emissions measurement plan project for 2025 of \$2.6 million (including the piloting of a mobile ground emissions measurement technology).

   Please discuss whether this level of annual spending is expected to allow Enbridge Gas to meet its goals of developing a measurement informed inventory, company-specific emission factors for DO over time, etc. If not, please provide a high-level estimate of potential annual costs in future years associated with these activities. As part of this response, please discuss whether Enbridge Gas is of the view that annual costs could reach the levels described at Exhibit D, Tab 1, page 61, Table 11 (i.e., ranging from \$10 million to \$33.1 million USD depending on technology or mix of technologies).

i) With respect to the incremental staffing costs, please further discuss why the additional work related to this project could not be managed with Enbridge Gas's existing resources. As part of the response, please discuss the type of work that the Carbon Strategy team is currently responsible for.

Response:

a) Enbridge Gas does not retroactively bill new customers for gas beyond the date on which a new customer has agreed to take responsibility for gas usage. Where there is a gap in account ownership, Enbridge Gas will make reasonable attempts to gather additional information regarding the property closing date or lease start date by communicating directly with the new customer or through the property ownership search functionality via GeoWarehouse.[1] In the event there remains a vacancy period between previous and new customers, the gas consumed during the vacancy period would be considered UFG, and would represent a portion of the volumes recorded in the UAFVA.

b) Enbridge Gas does currently apply pressure elevation factors to customers' bills. Please see the response at Exhibit I.FRPO-26 part b), for further discussion regarding pressure elevation factors and the initiative described.

[1] Exhibit D, Tab 1, p.35.

c) Confirmed.

d) The volumetric charges during these low flow conditions may be unbilled or billed inaccurately.

e) Leak volumes were estimated using emission factors and direct measurement, in accordance with the provincial and federal GHG reporting programs. Please refer to Exhibit D, Tab 1, Attachment 1, page 49, Section 7.5.1 for more details. Please see Table 1 for a breakdown of the 2022 leak volumes by STO and DO.

Table 1

2022 Leak Volumes

Segment	Leak Volume (10^3 scm)
STO	2,913
DO	15,205
TOTAL	18,118

f) Enbridge Gas applied the fugitive emissions uncertainties[2] to the 2022 leak volumes[3], yielding the leak emissions ranges set out in Table 2.

Table 2

Leak Ranges Based on Clearstone Uncertainty

Segment	Fugitive Uncertainty (%)	Leak Volume (10^3 scm)	Lower Range (10^3 scm)	Upper Range (10^3 scm)
STO	8.2[4]	2,913	2,674	3,152
DO	117.6	15,205	-2,676	33,086

For these calculations, the emissions were assumed to exhibit symmetrical confidence intervals. Depending on the underlying distribution of data, emissions may exhibit asymmetrical confidence intervals, which could change the upper and lower ranges. Enbridge Gas notes that the lower DO bound, which reflects negative emissions, would not be representative of physical system emissions.

[2] Exhibit D, Tab 1, Attachment 1, p.53.
[3] Exhibit D, Tab 1, p.61.
[4] For the purpose of this table, the fugitive uncertainty for combined storage and transmission operations (STO), was conservatively assumed to be the higher of the two values between storage (3.1%) and transmission (8.2%).

The proposed fugitive emissions Investigation Plan[5] includes the development of company-specific emission factors, with associated confidence intervals, based on direct measurements for a subset of Company assets. Should Enbridge Gas receive approval to move forward with this work, one of the goals would be to develop more accurate estimates of the Company's fugitive emissions and confidence levels.

g) Confirmed.

Accurately calculating the specific costs of fugitive emissions or any other contributing sources of UFG is extremely complex and time consuming. However, when using a simplified approach and applying the July 2024 EGD PGVA reference price, the UFG costs related to 2022 leaks is estimated at $3.0 million. There would be no reductions in carbon charges, as neither the federal carbon charge under the Federal Carbon Pricing Program, or the compliance obligations under the Ontario Emissions Performance Standard program apply to fugitive emissions.

h) This level of spending was identified for piloting select measurement technologies on a subset of distribution assets. Enbridge Gas expects the learnings from these pilot studies to inform potential future measurement targets and goals and elucidate potential future costs. The pilot studies are expected to provide information on technology suitability, location accuracy, ground follow-up requirements, additional leak management and repair requirements etc.

Cost estimates from various published sources often vary greatly based on the assumed scenarios used to arrive at costs. Without having obtained vendor quotes for the Enbridge Gas operating environment, the Company is unable to comment at this time on whether annual costs could reach or even exceed the levels described at Exhibit D, Tab 1, page 61, Table 11.

i) Enbridge Gas's existing resourcing (within various groups including Carbon Strategy, Leak Survey, and Operations) reflects the level of effort required to manage the existing emissions inventory and leak survey programs, which are compliant with provincial and federal regulatory requirements. The implementation of an added emissions measurement pilot is expected to result in increased requirements for data management and analysis, field support for the supervision and deployment of pilot technologies, and increased operational support for locating, classifying, and responding to leaks found outside of the regular compliance leak survey program. The required incremental resources will be dependent on and adjusted based on the results of the pilot.

[5] Exhibit D, Tab 1, pp.62-63.

The Carbon Strategy team includes five FTEs with current responsibilities that include:

GHG Reporting

- Leading regulatory reporting for GHG emissions to federal and provincial regulators for the gas distribution and storage (GDS) business unit, including Emissions Performance Standard (EPS) compliance reporting and verification.

Scope 1 and 2 Reduction Program

- Leading GHG emissions reduction strategy for GDS, including supporting the Enbridge Inc. corporate emissions strategy and targets.
- Supporting GHG emission assessments, economic risks and impacts for new project evaluations across the GDS business unit.

Methane Regulation Compliance and Advocacy

- Leading advocacy and compliance with GHG and climate change regulations, such as the Federal Methane Regulation. This includes participation in government consultations and environmental industry groups, such as Canadian Energy Partnership for Environmental Innovation (CEPEI).

Fugitive Emissions Measurement Plan

- Leading development and implementation of a Fugitive Emissions Measurement Plan (FEMP) to improve accuracy of fugitive emissions inventory.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex.F/T1/pp. 4-5
Ex.F/T2/S3/p. 1
Ex.F/T3/S3/p. 1

Question(s):

For the EGD rate zone, Enbridge Gas proposes to allocate the balance in the GOCA variance account related to the EGD rate zone to rate classes in proportion to the allocation of System Operation Distribution Operating Expenses approved by the OEB in EGD's 2018 Cost Allocation Study. For both the Union North and Union South rate zones, Enbridge Gas proposes to allocate the balance in the GOCA variance account related to the Union North and Union South rate zones to rate classes in proportion to the allocation of Mains and Services Distribution Operating O&M expenses by rate zone approved by the OEB in Union's 2013 Cost Allocation Study.

a) Please provide a reconciliation of the allocations of the GOCA balance to the rate classes shown at Exhibit F, Tab 2, Schedule 3, page 1, Column 11 and Exhibit F, Tab 3, Schedule 3, page 1, Line 30 to the allocations cited at footnotes 8 and 9 at Exhibit F, Tab 1, pages 4-5.

b) Please provide rationale supporting the EGD rate zone allocation of the GOCA balance to rate classes based on the allocation of "System Operation Distribution Operating Expenses."

c) Please provide rationale supporting the Union North and South rate zones allocation of the GOCA balance to rate classes based on the allocation of "Mains and Services Distribution Operating O&M expenses by rate zone."

Response:

a) Please see Attachment 1 for the reconciliation of the GOCA Variance Account for the EGD rate zone. Attachment 1, pages 1 and 2, provide the calculation of the proposed GOCA Variance Account allocation factor and allocation to rate classes for the EGD rate zone. Attachment 1, pages 3, 4, and 5 show the functionalization, classification, and the factors used to allocate System Operation Distribution

Operating Expenses approved by the OEB in EGD's 2018 Cost Allocation Study, respectively.

Please see Attachment 2 for the reconciliation of the GOCA Variance Account for the Union North rate zone. Attachment 2, page 1 provides the calculation of the proposed GOCA Variance Account allocation factor and allocation to rate classes for the Union North rate zone. Attachment 2, page 2 provides the allocation of Union North rate zone Mains and Services Distribution Operating O&M expenses approved by the OEB in Union's 2013 Cost Allocation study.

Please see Attachment 3 for the reconciliation of the GOCA Variance Account for the Union South rate zone. Attachment 3, page 1 provides the calculation of the proposed GOCA Variance Account allocation factor and allocation to rate classes for the Union South rate zone. Attachment 3, pages 2 and 3 provide the allocation of Union South rate zone Mains and Services Distribution O&M expenses approved by the OEB in Union's 2013 Cost Allocation study.

b) and c)

The purpose of the GOCA variance account is to track incremental pipeline locate costs resulting from the enactment of Bill 93. For the EGD rate zone, pipeline locate costs in current approved base rates are included and allocated to EGD rate classes in proportion to the allocation of System Operation Distribution Operating Expenses. For the Union North and Union South rate zones, pipeline locate costs in current approved base rates are included and allocated to Union North and Union South rate classes in proportion to the allocation of Mains and Services Distribution Operating O&M expenses by rate zone. Accordingly, Enbridge Gas is proposing to allocate the incremental pipeline locate costs associated with the GOCA variance account to rate classes in proportion to the allocation of similar pipeline locate costs included in base rates by rate zone.

Reconciliation of GOCA Variance Account - EGD Rate Zone
Functionalization and Classification of System Operation
Distribution Operating Expenses

Line No.	Particulars ($000's)	System Operation Distribution Operating Expenses
		(a)
	Functionalization of Costs (1)	
1	Cost of Service	46,468
2	Add: Fringe Benefits	10,425
3	Add: Supervision	10,497
4	Add: A&G Overhead	13,135
5	Total Costs	80,524
	Classification of Costs (2)	
6	TP Capacity <=4"	1,962
7	TP Capacity >4"	17,874
8	HP Capacity	5,657
9	LP Capacity	30,627
10	Customer Plant	24,404
11	Total Costs	80,524

Notes:
(1) Attachment 1, page 3, line 2.1.5.
(2) Attachment 1, page 4, line 2.3.

Reconciliation of GOCA Variance Account - EGD Rate Zone
Allocation of System Operation Distribution Operating Expenses
and Calculation of Proposed Allocation Factor

Line No.	Particulars	Rate 1	Rate 6	Rate 9	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
	Allocation Factors (1)														
1	TP Capacity <=4"	0.5038	0.4419	-	-	0.0246	0.0153	-	0.0001	0.0010	0.0010	0.0121	0.0001	1.0000	
2	TP Capacity >4"	0.4634	0.4064	-	-	0.0227	0.0140	0.0804	0.0000	0.0009	0.0009	0.0112	0.0001	1.0000	
3	HP Capacity	0.5100	0.4474	-	-	0.0249	0.0154	-	0.0001	0.0010	0.0010	-	0.0001	1.0000	
4	LP Capacity	0.5144	0.4512	-	-	0.0252	0.0070	-	0.0001	0.0010	0.0010	-	0.0002	1.0000	
5	Customer Plant	0.9231	0.0768	-	-	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000	
	Allocation of Costs														
6	TP Capacity <=4"	988	867	-	-	48	30	-	0	2	2	24	0	1,962	(2)
7	TP Capacity >4"	8,282	7,265	-	-	405	251	1,436	1	17	16	200	2	17,874	(3)
8	HP Capacity	2,885	2,531	-	-	141	87	-	0	6	6	-	1	5,657	(4)
9	LP Capacity	15,755	13,819	-	-	770	214	-	2	32	31	-	5	30,627	(5)
10	Customer Plant	22,527	1,873	-	-	3	0	0	0	0	0	0	0	24,404	(6)
11	Total	50,437	26,354	-	-	1,368	582	1,436	3	56	55	223	8	80,524	
12	Proposed Allocation Factor	62.6%	32.7%	0.0%	0.0%	1.7%	0.7%	1.8%	0.0%	0.1%	0.1%	0.3%	0.0%	100.0%	(7)
13	Allocation of GOCA Variance Account	13,065	6,827	-	-	354	151	372	1	15	14	58	2	20,858	(8)

Notes:
(1) Attachment 1, page 5, lines 2.1 to 2.5.
(2) Attachment 1, page 1, line 6, allocated using line 1.
(3) Attachment 1, page 1, line 7, allocated using line 2.
(4) Attachment 1, page 1, line 8, allocated using line 3.
(5) Attachment 1, page 1, line 9, allocated using line 4.
(6) Attachment 1, page 1, line 10, allocated using line 5.
(7) Percentage calculated based on allocation calculated in line 11.
(8) Exhibit F, Tab 2, Schedule 3, page 1, col. 11.

Functionalization of
Ontario Utility O&M
Year Ended December 31, 2018

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Cost of Service	Fringe Benefits	Sub-Total	Supervision	Sub-Total	A&G Overhead	Total
	Gas Supply							
1.1	Gas Purchased	1,594.00	0.00	1,594.00	0.00	1,594.00	0.00	1,594.00
1.2	Gas Storage	192.19	2.43	194.62	0.00	194.62	0.00	194.62
1.3	A&G	0.00	0.00	0.00	0.00	0.00	10.48	10.48
1.4	System Gas Management	0.97	0.58	1.55	0.00	1.55	0.00	1.55
1.5	Direct Purchase Management	1.07	0.36	1.42	0.00	1.42	0.00	1.42
1.	Total Gas Supply	1,788.22	3.37	1,791.59	0.00	1,791.59	10.48	1,802.07
	Distribution Costs							
	Operating Costs							
2.1.1	Chart Processing	0.04	0.00	0.04	0.03	0.07	0.01	0.08
2.1.2	Distribution Sta.	1.29	0.70	1.99	1.17	3.16	0.62	3.78
2.1.3	Sub-total	1.33	0.70	2.03	1.20	3.23	0.63	3.86
2.1.4	Supervision M&R	0.46	0.37	0.82	(0.82)	0.00	0.00	0.00
2.1.5	System Operation	46.47	10.42	56.89	10.50	67.39	13.13	80.52
2.1.6	Sub-total	48.26	11.49	59.75	10.87	70.62	13.76	84.38
2.1.7	Supervision Dist Op	7.16	3.71	10.87	(10.87)	0.00	0.00	0.00
2.1.8	Gas Dispatched	4.97	2.07	7.04	0.00	7.04	1.37	8.41
2.1	Total Operating Costs	60.39	17.27	77.65	0.00	77.65	15.13	92.79
	Maintenance Costs							
2.2.1	Distribution Sys Reg	1.19	0.07	1.26	3.17	4.43	0.86	5.29
2.2.2	Sales Meters	0.83	0.34	1.17	2.94	4.11	0.80	4.92
2.2.3	Other Meters	1.86	0.93	2.79	7.02	9.82	1.91	11.73
2.2.4	Instruments	0.87	0.37	1.24	3.12	4.37	0.85	5.22
2.2.5	Sub-total M&R	4.75	1.72	6.47	16.26	22.73	4.43	27.16
2.2.6	Supervision M&R	6.18	2.55	8.73	(8.73)	0.00	0.00	0.00
2.2.7	Mains	9.14	2.69	11.83	13.77	25.59	4.99	30.58
2.2.8	Structures	0.31	0.17	0.47	0.55	1.02	0.20	1.22
2.2.9	Sub-total Mntce	20.38	7.12	27.50	21.85	49.35	9.62	58.96
2.2.10	Supervision Dist Mntce	15.06	6.78	21.85	(21.85)	0.00	0.00	0.00
2.2	Total Maintenance Costs	35.44	13.90	49.35	0.00	49.35	9.62	58.96
2.	Total Distribution Costs	95.83	31.17	127.00	0.00	127.00	24.75	151.75

Witnesses: A. Kacicnik
B. So

CLASSIFICATION OF O&M COSTS
Year Ended December 31, 2018

(millions of dollars)

Item No.	Description	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24
		DISTRIBUTION COSTS						CUSTOMER RELATED INVESTMENTS					
		TP Capacity <=4"	TP Capacity >4"	HP Capacity	LP Capacity	Commodity	Bad Debt Distribution	DSM	Meters	Sales Stations	Services	Customer Plant	Rentals
	GAS SUPPLY												
1.1	Gas Purchased	0.00	0.00	0.00	0.00	20.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.2	Stored Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.3	A&G	1.04	9.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.	Total Gas Supply	1.04	9.44	0.00	0.00	20.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION												
	OPERATING COSTS												
2.1	Chart Processing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	District Stations	0.13	1.20	0.38	2.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	1.96	17.87	5.66	30.63	0.00	0.00	0.00	0.00	0.00	0.00	24.40	0.00
2.4	Gas Dispatched	0.82	7.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
2.5	Dist. System Reg.	0.19	1.69	0.53	2.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.92	0.00	0.00	0.00
2.7	Other Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.73	0.00	0.00	0.00	0.00
2.8	Instruments	0.52	4.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	0.46	4.21	1.33	13.68	0.00	0.00	0.00	0.00	0.00	0.00	10.90	0.00
2.10	Structures	0.24	0.03	0.01	0.06	0.01	0.00	0.00	0.01	0.00	0.18	0.04	0.00
2.	Total Distribution Costs	4.32	37.20	7.91	49.31	0.01	0.00	0.00	11.74	4.92	0.18	35.35	0.00
	CUSTOMER SERVICE												
	OPERATING COSTS												
3.1	Appliance Inspection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Locks/Unlocks/Exchanges	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
3.3	Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.66	0.00	0.00
3.	Total Customer Service	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.66	0.00	0.00
	SALES/MARKETING												
4.1	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.4	General Promotion	0.70	6.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	Merchandising Ex.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	0.00	0.00	0.00	0.00	0.00	0.00	66.49	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	0.00	0.00	0.00	0.00	0.00	0.00	20.41	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	0.70	6.34	0.00	0.00	0.00	0.00	86.90	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING												
5.1	Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.2	Enquiry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.3	Readings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.4	Credit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Large Volume Customer Care	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.6	Uncollectibles	0.00	0.00	0.00	0.00	0.00	8.27	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	0.00	0.00	0.00	0.00	0.00	8.27	0.00	0.00	0.00	0.00	0.00	0.00
6.	**Total O&M**	6.05	52.98	7.91	49.31	20.66	8.27	86.90	11.74	4.92	10.84	35.35	0.00
7.	Fixed Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	**Total O&M Expense**	6.05	52.98	7.91	49.31	20.66	8.27	86.90	11.74	4.92	10.84	35.35	0.00

Witnesses: A. Kacicnik
B. So

Witnesses: A. Kacicnik
B. So

ALLOCATION PERCENTAGES
Year Ended December 31, 2018

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
		FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 300 Int	Direct Purchase
	Commodity Responsibility															
1.1	Annual Sales	1.0000	0.5779	0.3927	0.0000	0.0000	0.0071	0.0000	0.0000	0.0006	0.0011	0.0043	0.0163	0.0000	0.0000	0.0000
1.2	Bundled Annual Deliveries	1.0000	0.4140	0.4201	0.0000	0.0000	0.0686	0.0472	0.0000	0.0056	0.0044	0.0253	0.0148	0.0000	0.0000	0.0000
1.3	Total Annual Deliveries	1.0000	0.4140	0.4201	0.0000	0.0000	0.0686	0.0472	0.0000	0.0056	0.0044	0.0253	0.0148	0.0000	0.0000	0.0000
1.4	Bundled Peak Delivery	1.0000	0.5039	0.4420	0.0000	0.0000	0.0246	0.0153	0.0000	0.0001	0.0010	0.0010	0.0121	0.0000	0.0000	0.0000
1.5	System Gas Sales	1.0000	0.5779	0.3927	0.0000	0.0000	0.0071	0.0000	0.0000	0.0006	0.0011	0.0043	0.0163	0.0000	0.0000	0.0000
1.6	Bundled Transportation Deliveries	1.0000	0.5342	0.4164	0.0000	0.0000	0.0249	0.0013	0.0000	0.0022	0.0012	0.0049	0.0149	0.0000	0.0000	0.0000
	Distribution Capacity Responsibility															
2.1	Delivery Demand TP > 4"	1.0000	0.4634	0.4064	0.0000	0.0000	0.0227	0.0140	0.0804	0.0000	0.0009	0.0009	0.0112	0.0001	0.0000	0.0000
2.2	Delivery Demand TP <= 4"	1.0000	0.5039	0.4419	0.0000	0.0000	0.0246	0.0153	0.0000	0.0001	0.0010	0.0010	0.0121	0.0001	0.0000	0.0000
2.3	Delivery Demand HP	1.0000	0.5100	0.4473	0.0000	0.0000	0.0249	0.0154	0.0000	0.0001	0.0010	0.0010	0.0000	0.0001	0.0000	0.0000
2.4	Delivery Demand LP	1.0000	0.5144	0.4512	0.0000	0.0000	0.0252	0.0070	0.0000	0.0001	0.0010	0.0010	0.0000	0.0002	0.0000	0.0000
2.5	Cust. Rel Plant	1.0000	0.9231	0.0768	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Storage Responsibility															
3.1	Deliverability	1.0000	0.5495	0.4380	0.0000	0.0000	0.0023	0.0009	0.0000	0.0000	0.0000	0.0000	0.0093	0.0000	0.0000	0.0000
3.2	Space	1.0000	0.4865	0.4669	0.0000	0.0000	0.0175	0.0043	0.0000	0.0000	0.0025	0.0064	0.0160	0.0000	0.0000	0.0000
	Customer Responsibility															
4.1	Meters	1.0000	0.5613	0.4199	0.0000	0.0000	0.0099	0.0010	0.0041	0.0016	0.0012	0.0009	0.0000	0.0000	0.0000	0.0000
4.2	Sales Stations	1.0000	0.0748	0.8470	0.0000	0.0000	0.0348	0.0067	0.0000	0.0142	0.0096	0.0122	0.0000	0.0007	0.0000	0.0000
4.3	Services	1.0000	0.8875	0.1093	0.0000	0.0000	0.0016	0.0002	0.0001	0.0002	0.0004	0.0007	0.0000	0.0000	0.0000	0.0000
4.4	Rental Equipment	1.0000	0.2000	0.8000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.5	Total Customer Count	1.0000	0.9231	0.0768	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.6	Comm / Ind. Customer Count	1.0000	0.0000	0.9976	0.0000	0.0000	0.0016	0.0002	0.0000	0.0003	0.0002	0.0001	0.0000	0.0000	0.0000	0.0000
4.7	Contracts	1.0000	0.0000	0.0000	0.0000	0.0000	0.6592	0.0672	0.0100	0.1070	0.0896	0.0622	0.0025	0.0025	0.0000	0.0000
4.8	Chart Readings non AMR per year	1.0000	0.0000	0.9852	0.0000	0.0000	0.0084	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0064	0.0000	0.0000
4.9	Chart Readings AMR per year	1.0000	0.0000	0.8496	0.0000	0.0000	0.0932	0.0122	0.0017	0.0151	0.0155	0.0126	0.0000	0.0000	0.0000	0.0000
4.10	Meter Readings per year	1.0000	0.9259	0.0741	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.11	Separation Expense Allocator	1.0000	0.7750	0.2250	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.12	Direct Purchase Customers	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
5.	Rate Base	1.0000	0.6781	0.2893	0.0000	0.0000	0.0124	0.0045	0.0100	0.0006	0.0010	0.0014	0.0026	0.0001	0.0000	0.0000

Reconciliation of GOCA Variance Account
Union North Rate Zone

Line No.	Particulars	Proposed Allocation Factor Union North Mains and Services Distribution Operating O&M expenses ($000's) (1)	(%)	Allocation of GOCA Variance Account (2) ($000's)
		(a)	(b)	(c)
1	Rate 01	5,308	81.8%	2,010
2	Rate 10	450	6.9%	170
3	Rate 20	336	5.2%	127
4	Rate 25	100	1.5%	38
5	Rate 100	294	4.5%	111
16	Total	6,487	100.0%	2,456

Notes:
(1) Attachment 2, page 2, F. Distribution (Northern Ontario), i. Operating, Mains & Services line.
(2) Exhibit F, Tab 3, Schedule 3, page 1, line 30.

UNION GAS LIMITED
Fully Allocated Cost of Service Study for 2013
Total Allocation Detail Report
($000's)

Account Description	Account Code	Account Dollars	Small Volume General Firm Service R01	Large Volume General Firm Service R10	Medium Volume Firm Service R20	Large Volume High Load Factor Firm Service R100	Large Volume Interruptible Service R25
F. DISTRIBUTION (Northern Ontario)							
i. Operating							
Supervision- Plant Service	670.1	0	0	0	0	0	0
Supervision- Customer Service	670.2	0	0	0	0	0	0
Meter & Regulator Removal & Resetting	673	2,228	2,183	45	0	0	0
Meter Turn-ons & Turn-offs		705	691	14	0	0	0
Service on Customer Premise	674	2,063	2,018	45	0	0	0
New Appliance Inspec., Repair., Repl.		0	0	0	0	0	0
Mains & Services	675	6,487	5,308	450	336	294	100
Compressor	676	0	0	0	0	0	0
Leakage Survey		0	0	0	0	0	0
Measuring and Regulating	677	4,730	1,764	563	973	1,183	246
Other- Plant Service	679.1	0	0	0	0	0	0
Other- Customer Service	679.2	0	0	0	0	0	0
Other - General Operating	679.3	0	0	0	0	0	0
Distribution Operating Transferred		0	0	0	0	0	0
ii. Maintenance							
Supervision- Plant Service	870.1	0	0	0	0	0	0
Supervision- Customer Service	870.2	0	0	0	0	0	0
Supervision- Meter Shop	870.3	0	0	0	0	0	0
Structures & Improvements	872	0	0	0	0	0	0
Equipment on Customer Premises	873	765	750	15	0	0	0
Mains	875.1	3,871	3,119	286	215	188	64
Services	875.2	0	0	0	0	0	0
Compressor	876	0	0	0	0	0	0
Measuring and Regulating	877	220	82	26	45	55	11
Meter & Regulator Repair	878	54	0	27	11	6	9
Other- Plant Service	879.1	0	0	0	0	0	0
Other- Customer Service	879.2	22	21	0	0	0	0
Other- Meter Shop	879.3	952	931	21	0	0	0
Other- General Maintenance	879.4	0	0	0	0	0	0
Distribution Maintenance Transferred		0	0	0	0	0	0
Subtotal		22,097	16,868	1,492	1,581	1,726	430
G. GENERAL OPERATING AND ENGINEERING							
System Operation & Engineering	685	37,145	6,873	903	854	569	302
Other	688	513	96	13	9	7	3
Scada	684	1,463	265	37	25	20	7
General Operations Transferred	689	0	0	0	0	0	0
Subtotal		39,121	7,234	953	889	596	312
H. SALES PROMOTION AND MERCHANDISE							
Sales Promotion Supervision	700	8,322	973	91	392	227	411
Advertising	701	0	0	0	0	0	0
Home Service, Special Campaigns		0	0	0	0	0	0
Displays, Dealer Service, Other		0	0	0	0	0	0
Demand Side Management		31,641	3,732	1,186	974	1,798	0
Merchandise Sales Net Income		0	0	0	0	0	0
Other	709	354	22	1	23	16	28
Subtotal		40,318	4,726	1,279	1,389	2,041	438

Reconciliation of GOCA Variance Account
Union South Rate Zone

Line No.	Particulars	Proposed Allocation Factor Union South Mains and Services Distribution Operating O&M expenses ($000's) (1)	(%)	Allocation of GOCA Variance Account (2) ($000's)
		(a)	(b)	(c)
1	Rate M1	12,371	83.6%	8,629
2	Rate M2	1,070	7.2%	746
3	Rate M4	268	1.8%	187
4	Rate M5	367	2.5%	256
5	Rate M7	86	0.6%	60
6	Rate M9	-	0.0%	-
8	Rate T1	185	1.2%	129
9	Rate T2	455	3.1%	317
10	Rate T3	-	0.0%	-
16	Total	14,802	100.0%	10,325

Notes:
(1) Attachment 3, pages 2-3, E. Distribution (Southern Ontario), i. Operating, Mains & Services line.
(2) Exhibit F, Tab 3, Schedule 3, page 1, line 30.

UNION GAS LIMITED
Fully Allocated Cost of Service Study for 2013
Total Allocation Detail Report
($000's)

Account Description	Account Code	Account Dollars	Gen. Service Small Volume M1	Gen. Service Large Volume M2	Firm Contract M4	Interruptible Contract- Firm M5	Interruptible Contract- Interruptible M5	Special Large Volume Contract - Firm M7	Special Large Volume Contract - Interruptible M7	Large Wholesale Service M9	Small Wholesale Service M10
E. DISTRIBUTION (Southern Ontario)											
i. Operating											
Supervision- Plant Service	670.1	0	0	0	0	0	0	0	0	0	0
Supervision- Customer Service	670.2	0	0	0	0	0	0	0	0	0	0
Meter & Regulator Removal & Resetting	673	4,245	4,158	87	0	0	0	0	0	0	0
Meter Turn-ons & Turn-offs		2,117	2,074	43	0	0	0	0	0	0	0
Service on Customer Premise	674	4,306	4,210	96	0	0	0	0	0	0	0
New Appliance Inspec., Repair., Repl.		0	0	0	0	0	0	0	0	0	0
Mains & Services	675	14,802	12,371	1,070	268	5	362	82	4	0	0
Compressor	676	0	0	0	0	0	0	0	0	0	0
Leakage Survey		0	0	0	0	0	0	0	0	0	0
Measuring and Regulating	677	631	367	123	35	1	48	7	0	0	0
Other- Plant Service	679.1	0	0	0	0	0	0	0	0	0	0
Other- Customer Service	679.2	0	0	0	0	0	0	0	0	0	0
Other - General Operating	679.3	0	0	0	0	0	0	0	0	0	0
Distribution Operating Transferred		0	0	0	0	0	0	0	0	0	0
ii. Maintenance											
Supervision- Plant Service	870.1	0	0	0	0	0	0	0	0	0	0
Supervision- Customer Service	870.2	0	0	0	0	0	0	0	0	0	0
Supervision- Meter Shop	870.3	0	0	0	0	0	0	0	0	0	0
Structures & Improvements	872	0	0	0	0	0	0	0	0	0	0
Equipment on Customer Premises	873	1,729	1,690	39	0	0	0	0	0	0	0
Mains	875.1	7,816	6,400	620	157	3	212	48	2	0	0
Services	875.2	0	0	0	0	0	0	0	0	0	0
Compressor	876	0	0	0	0	0	0	0	0	0	0
Measuring and Regulating	877	2,228	1,298	436	123	2	170	26	0	0	0
Meter & Regulator Repair	878	372	0	157	33	0	36	14	2	2	0
Other- Plant Service	879.1	0	0	0	0	0	0	0	0	0	0
Other- Customer Service	879.2	13	12	0	0	0	0	0	0	0	0
Other- Meter Shop	879.3	987	965	22	0	0	0	0	0	0	0
Other- General Maintenance	879.4	0	0	0	0	0	0	0	0	0	0
Distribution Maintenance Transferred		0	0	0	0	0	0	0	0	0	0
Subtotal		39,246	33,546	2,694	616	11	828	179	8	2	0

UNION GAS LIMITED
Fully Allocated Cost of Service Study for 2013
Total Allocation Detail Report
($000's)

Account Description	Account Code	Account Dollars	Storage & Transportation Service - Firm T1	Storage & Transportation Service - Interruptible T1	Storage & Transportation Service - Firm T2	Storage & Transportation Service - Interruptible T2	Wholesale Storage & Transportation Service T3	Excess Utility Storage Space	Firm Transportation Service C1	Interruptible Trans. Service & Exchanges C1	Dawn-Trafalgar Transport Service M12	Local Production Transportation Service M13	Storage Transportation Service M16
E. DISTRIBUTION (Southern Ontario)													
i. Operating													
Supervision- Plant Service	670.1	0	0	0	0	0	0	0	0	0	0	0	0
Supervision- Customer Service	670.2	0	0	0	0	0	0	0	0	0	0	0	0
Meter & Regulator Removal & Resetting	673	4,245	0	0	0	0	0	0	0	0	0	0	0
Meter Turn-ons & Turn-offs		2,117	0	0	0	0	0	0	0	0	0	0	0
Service on Customer Premise	674	4,306	0	0	0	0	0	0	0	0	0	0	0
New Appliance Inspec., Repair., Repl.		0	0	0	0	0	0	0	0	0	0	0	0
Mains & Services	675	14,802	170	15	332	123	0	0	0	0	0	0	0
Compressor	676	0	0	0	0	0	0	0	0	0	0	0	0
Leakage Survey		0	0	0	0	0	0	0	0	0	0	0	0
Measuring and Regulating	677	631	22	2	15	10	0	0	0	0	0	0	0
Other- Plant Service	679.1	0	0	0	0	0	0	0	0	0	0	0	0
Other- Customer Service	679.2	0	0	0	0	0	0	0	0	0	0	0	0
Other - General Operating	679.3	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Operating Transferred		0	0	0	0	0	0	0	0	0	0	0	0
ii. Maintenance													
Supervision- Plant Service	870.1	0	0	0	0	0	0	0	0	0	0	0	0
Supervision- Customer Service	870.2	0	0	0	0	0	0	0	0	0	0	0	0
Supervision- Meter Shop	870.3	0	0	0	0	0	0	0	0	0	0	0	0
Structures & Improvements	872	0	0	0	0	0	0	0	0	0	0	0	0
Equipment on Customer Premises	873	1,729	0	0	0	0	0	0	0	0	0	0	0
Mains	875.1	7,816	99	9	194	72	0	0	0	0	0	0	0
Services	875.2	0	0	0	0	0	0	0	0	0	0	0	0
Compressor	876	0	0	0	0	0	0	0	0	0	0	0	0
Measuring and Regulating	877	2,228	78	6	53	36	0	0	0	0	0	0	0
Meter & Regulator Repair	878	372	15	7	79	16	10	0	0	0	0	0	0
Other- Plant Service	879.1	0	0	0	0	0	0	0	0	0	0	0	0
Other- Customer Service	879.2	13	0	0	0	0	0	0	0	0	0	0	0
Other- Meter Shop	879.3	987	0	0	0	0	0	0	0	0	0	0	0
Other- General Maintenance	879.4	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Maintenance Transferred		0	0	0	0	0	0	0	0	0	0	0	0
Subtotal		39,246	383	39	674	257	10	0	0	0	0	0	0

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

EB-2024-0125/Cover Letter (May 31, 2024)
Ex. H/T1/S2/p. 6
EB-2022-0200/Settlement Proposal/p. 18

Question(s):

In its original cover letter for the EB-2024-0125 application, Enbridge Gas stated that, "included with the application, Enbridge Gas is providing the OEB Scorecard and the Indigenous Working Group Report. No approval is being sought regarding these items."

The OEB approved EB-2022-0200 settlement proposal states that:

i. Until the end of 2024, the budget for the IWG is $640,000.
ii. For each subsequent year, the IWG shall establish a budget which will be subject to review, or approval, by the OEB.
iii. Enbridge Gas will establish the IWG deferral account to record actual capacity funding costs, which will be subject to review and clearance in the applicable DVA proceeding.

a) Please confirm that Enbridge Gas intends to seek disposition of the September 2023 to December 31, 2024 balance in the IWG deferral account in its 2024 ESM and DVA proceeding (to be filed in Summer 2025).

b) Please advise whether Enbridge Gas is seeking OEB approval, in the current proceeding, for the increase to the budget for IWG capacity funding from $640,000 (2024) to $800,000 (2025).

Response:

a) Confirmed.

b) Please see Exhibit I.STAFF-16 part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. H/T1/S2/Appendix A/pp. 10-11, 19

Question(s):

At Exhibit H, Tab 1, Schedule 2, Appendix A, pages 10-11, a summary table of issues to be discussed by the IWG is provided. As part of that table, there is reference to certain topics where third-party experts are to be retained.

At Exhibit H, Tab 1, Schedule 2, Appendix A, page 19, the minutes for the April 30, 2024 meeting state that, "Brattle Group is close to being retained by the Indigenous parties. The main focus of Brattle Group as contemplated by the Indigenous parties will be to review the expert reports from the rebasing application and determine what is important information that may have been missed in those reports that would help mitigate energy-related risks and identify energy-related opportunities of First Nation groups in Ontario. There is also an expectation that other experts will be retained to address other significant issues relevant to the IWG. A potential example of these additional topics is fugitive emissions."

a) Please provide a status update regarding the retention of experts to address the following subject areas. As part of the response, please advise whether an expert has already been retained, whether there are still plans to retain an expert, or whether there is no longer a plan to retain an expert.
    i. RNG
    ii. Stranded assets
    iii. Need, benefits and cost of energy transition
    iv. Fugitive emissions

b) If Brattle Group has already been retained, please advise for which subject area (as described at Exhibit H, Tab 1, Schedule 2, Appendix A, pages 10-11) it has been retained to provide expert support.

c) Please explain how any expert reports/presentations that are provided to the IWG will be used with respect to rates, facilities or other applications filed with the OEB.

Response

a) and b)

The Brattle Group has been retained by the Indigenous parties to focus on energy transition.

c) The Brattle Group will prepare a report for the Indigenous parties to present to Enbridge Gas. Until Enbridge Gas is provided with the Brattle Group report or any other expert report to be commissioned by the Indigenous parties, Enbridge Gas cannot comment on the manner in which such reports may be used to inform issues related to rates, facilities and other applications filed with the OEB.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit A, Tab 3, Page 3

Question(s):

On page 3, Enbridge refers to and relies on a number of decisions and settlement agreements relating to UFG. Please provide excerpts of all portions of those decisions and settlements relating to UFG.

Response:

The following are the relevant excepts from OEB Decisions and settlement agreements relating to UFG.

1) Excerpts from EB-2022-0110 - Settlement Proposal

2(c) Unaccounted for Gas Variance Account (2021 UAFVA)

All parties agree that the principal balance in the 2021 UAFVA ($0.754 million) which is shown in Appendix A, along with applicable interest, will be cleared as set out under Issue 4, below.

All parties agree that the clearance of this account is on an interim basis until further clarification regarding the calculation of UAF/UFG is provided in the 2022 Earnings Sharing and Deferral and Variance Account clearance application, as described in more detail at Item 3(o) below.[1]

3(o) Unaccounted for Gas (UFG) Volume Variance Account (179-135)

All parties agree that the principal balance in the Unaccounted for Gas (UFG) Volume Variance Account ($20.501 million), which is shown in Appendix A, along with applicable interest, will be cleared as set out under Issue 4, below.

[1] EB-2022-0110, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, October 11, 2022, p.13.

All parties agree that the clearance of this account is on an interim basis until the further clarification regarding the calculation of UAF/UFG is provided in the 2022 Earnings Sharing and Deferral and Variance Account clearance application, as described in more detail below (this same provision applies to items 2(c) and 3(p)).

In connection with the settlement of this item (as well as items 2(c) and 3(o), each of which also relate to UAF/UFG), Enbridge Gas agrees that it will address the following items in evidence in the 2022 Deferral and Variance Account clearance application:

(i) Detailed evidence on the derivation of UFG balances, including evidence on items such as:
- (a) the process used to determine forecast and actual UFG at the end of each year and the beginning of the following year,
- (b) the way that UFG is determined on an ongoing basis as forecast (unbilled) volumes are billed, and
- (c) the impact of billing adjustments on UFG.

(ii) A continuity schedule showing forecast and actual UFG on a monthly basis for 2020, 2021 and 2022.[2]

3(p) Unaccounted for Gas (UFG) Price Variance Account (179-141)

All parties agree that the principal balance in the Unaccounted for Gas (UFG) Price Variance Account ($8.151 million), which is shown in Appendix A, along with applicable interest, will be cleared as set out under Issue 4, below.

All parties agree that the clearance of this account is on an interim basis until further clarification regarding the calculation of UAF/UFG is provided in the 2022 Earnings Sharing and Deferral and Variance Account clearance application, as described in more detail at Item 3(o) above[3]

2) <u>Excerpt from EB-2022-0100 – Decision on Settlement Proposal and Rate Order</u>

Consistent with the settlement proposal, the 2021 balances in the UFG-related DVAs will be disposed of on an interim basis in both the EGD and Union rates zones.

Enbridge Gas further committed to filing the following additional information in its 2022 DVA and Earnings Sharing application:

- Detailed evidence on the derivation of UFG balances, including evidence on items such as:

[2] EB-2022-0110, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, October 11, 2022 pp.19-20.
[3] ibid, p.20.

   i. the process used to determine forecast and actual UFG at the end of each year and the beginning of the following year,
   ii. the way that UFG is determined on an ongoing basis as forecast (unbilled) volumes are billed, and
   iii. the impact of billing adjustments on UFG.
- A continuity schedule showing forecast and actual UFG on a monthly basis for 2020, 2021 and 2022.[4]

3) Excerpts from EB-2023-0092 - Settlement Proposal

2(c) Unaccounted for Gas Variance Account (2022 UAFVA)

All parties agree that the principal balance in the 2022 UAFVA, which is shown in Appendix A, along with applicable interest, will be cleared as set out under Issue 4, below.

All parties agree that the clearance of this account balance is on an interim basis until further evidence describing the Company's ongoing review and investigation of UAF/UFG is provided in the 2023 Deferral Account Clearance application, as described in more detail at Item 3(q) below.[5]

3(q) Unaccounted for Gas (UFG) Volume Variance Account (179-135)

All parties agree that the principal balance in the Unaccounted for Gas (UFG) Volume Variance Account, which is shown in Appendix A, along with applicable interest, will be cleared as set out under Issue 4, below.

All parties agree that the clearance of this account is on an interim basis until the further evidence describing the Company's ongoing review and investigation of UAF/UFG is provided in the 2023 Deferral Account Clearance application, as described in more detail below (this same provision applies to items 2(c) and 3(r)).

In connection with the settlement of this item (as well as items 2(c) and 3(r), each of which also relate to UAF/UFG), Enbridge Gas agrees that it will address the following items in evidence in the 2023 Deferral Account Clearance application:

Detailed evidence will be filed about the items learned and future plans arising from the ongoing review and investigation of UFG (see Exhibit I.Staff.6), including (without limitation):

[4] EB-2022-0110, Decision on Settlement Proposal and Rate Order, November 8, 2022, pp. 4-5.
[5] EB-2023-0092, Settlement Proposal, November 28, 2023, Exhibit N1, Tab 1, Schedule 1, p. 12.

(a) the work completed by Enbridge Gas during 2023 and 2024 and the resulting observations and learnings,
(b) the impact on UFG from "no bill" customers / volumes that are later billed,
(c) the role, if any, played by line pack in transmission and other high pressure systems in the incidence and determination of UFG,
(d) the Company's investigation plan for assessing fugitive emissions, as agreed in the EB-2022-0200 Settlement Proposal – Exhibit O1, Tab 1, Schedule 1, Issue 18(d), page 37.[6]

3(r) Unaccounted for Gas (UFG) Price Variance Account (179-141)

All parties agree that the principal balance in the Unaccounted for Gas (UFG) Price Variance Account, which is shown in Appendix A, along with applicable interest, will be cleared as set out under Issue 4, below.

All parties agree that the clearance of this account is on an interim basis until further evidence describing the Company's ongoing review and investigation of UAF/UFG is provided in the 2023 Deferral Account Clearance application, as described in more detail at Item 3(q) above.[7]

4) <u>Excerpt from EB-2023-0092 - Decision on Settlement Proposal and Rate Order</u>

Consistent with the settlement proposal, the 2022 balances in the Unaccounted for Gas (UFG)-related DVAs will be disposed of on an interim basis in the EGD and Union rates zones.

The OEB notes that, as part of the settlement proposal, Enbridge Gas committed to filing the following information in its 2023 DVA and earnings sharing application:

- Detailed evidence about the lessons learned and future plans arising from Enbridge Gas's ongoing review and investigation of UFG, including (without limitation):
    - the work completed by Enbridge Gas during 2023 and 2024 and the resulting observations and learnings
    - the impact on UFG from "no bill" customers / volumes that are later billed.
    - the role, if any, played by line pack in transmission and other high-pressure systems in the incidence and determination of UFG
    - the Company's investigation plan for assessing fugitive emissions.[8]

[6] EB-2023-0092, Settlement Proposal, Exhibit N1, Tab 1, Schedule 1, November 28, 2023. p.19-20.
[7] Ibid, p.20.
[8] EB-2023-0092, Decision on Settlement Proposal and Rate Order, February 6, 2024, p.4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Page 2

Question(s):

a) Please provide Enbridge’s understanding of the allowable scope for O&M spending for the purposes of ESM calculations. Please provide all relevant criteria.

b) For example, is it a requirement that purpose of all O&M spending being to provide gas distribution services to customers?

c) Enbridge spent $5.4 million on donations and memberships in 2023. Please provide a list of the 10 most expensive donations and 10 most expensive memberships in 2023.

d) How much did Enbridge spend on marketing in 2023? Please include salaries. Please include a list of the 5 most expensive line items.

e) How much did Enbridge spend research and development in 2023? Please provide a breakdown between spending from the DSM budget and spending outside the DSM budget.

f) How much did Enbridge spend on research and development relating to gas heat pumps in 2023?

Response:

a) and b)

The O&M expenditures that are incurred by the utility in relation to utility results for ESM purposes are representative of actual costs incurred and recognized by Enbridge Gas in its actuals as reported in its external financial statements prepared in accordance with US GAAP. The O&M costs represent the costs required to carry out typical utility operations. They include salaries and wages, contract services, materials and supplies, rents and leases, and employee-related costs, among other costs incurred in the operation of the utility. The makeup of costs reported in actuals and for ESM are in line with the costs as provided on a forecast basis for cost of service purposes which are approved by the OEB through the utility's rebasing application process.

c) Although this category is called 'donations and memberships', Enbridge Gas donations are excluded from Utility O&M and are, therefore, not part of the $5.4 million. To be responsive to the questions, Enbridge Gas has provided the top 10 sponsorships and the top 10 memberships within the $5.4 million.

Sponsorships

Fire Marshal's Public Fire Safety Council
Habitat for Humanity Canada
Build a Dream to Empower Women
First Robotics Canada
Forests Ontario
The Earth Rangers Foundation
Skills Canada
No. 9 Contemporary Art and the Environment
Industrial Gas Users Association
Ducks Unlimited Inc

Memberships

Canadian Gas Association
Utilization Technology Development
Canadian Natural Gas Vehicle Alliance
Ottawa Board of Trade
Energy Solutions Center Inc.
Ontario Regional Common Ground Alliance
Business Higher Education Roundtable
Canadian Manufacturers and Exporters
International Emissions Trading Association
Canadian Biogas Association

d) Enbridge Gas spent a total of $4.7 million on marketing in 2023. The top five line items, including salaries, are listed below.

1. Salaries of marketing department employees
2. Marketing for customer care, such as, meter reading, moves and My Account
3. Marketing for safety campaigns, such as, CO safety, clear your meter
4. Marketing for damage prevention, such as, importance of locates, Ontario One call
5. Marketing for RNG and CNG

di) Enbridge Gas spent $6.3 million in research and development in 2023. Spending outside of DSM totaled $4.2 million and DSM spending totaled $2.1 million. The DSM total reflects project spending through the Research and Innovation Fund (RIF) and does not include salaries of supporting staff.

dii) Enbridge Gas spent $0.88 million on research and development related to gas heat pumps in 2023. Spending outside of DSM totaled $0.56 million and DSM spending totaled $0.32.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit C, Tab 1, Page 19

Question(s):

a) Please provide an estimate of the savings to customers arising from the East Kingston Creekford Rd. IRP alternative. Please include the underlying calculations, ideally in a spreadsheet.

b) Why is Enbridge not seeking shared savings or another incentive in relation to this first IRP alternative?

Response:

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

b) Enbridge Gas has not established its IRP incentive proposal. The proposal will be filed for OEB approval with the first non-pilot IRP Plan application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1

Question(s):

a) Please add columns to Table 1 on Page 6 for each rate zone, the year-over-year percent change for each rate zone, and for the total for Union and Enbridge. Please explain the difference between UAF and UFG. If they are different, please also provide the requested table for UFG. For both, please also add rows for 2024 (annualized) and for the totals over the whole period.

b) Please provide a table showing the total UFG from 1991 to 2023 for Enbridge and its predecessors, an average annual commodity cost for each year, and the cost of the UFG for each year. Please also add a row for 2024 and for the totals over the whole period.

c) Please file the 2019 UFG Report referred to on page 10 so it will be properly on the record and can be referred to with an exhibit number.

d) Please file the UFG Progress Report and Supplemental UFG Progress Report referred to on page 30 so they will be properly on the record and can be referred to with an exhibit number.

e) Please provide the global warming impact (tonnes CO_2e) of 1 m^3 of combusted natural gas and 1 m^3 of natural gas vented to the atmosphere.

Response:

a) Please see Attachment 1 to this response for the historical UFG volumes for each rate zone separately as well as on a combined basis, as well as the year-over-year change for the same.

   UAF is the term used in reference to distribution losses in the EGD rate zone. UFG is the term used in reference to distribution, transmission and storage losses in the Union rate zones. As noted in the Company's pre-filed evidence:

All references to unaccounted for gas will be harmonized to be "UFG" effective January 2024, as described in the Company's 2024 Rebasing Phase 1 Application, EB-2022-0200, Exhibit 4, Tab 3, Schedule 1.[1]

b) Please see Attachment 2 for the historical UFG volumes for each rate zone separately as well as on a combined basis, as well as an average annual commodity cost for each year, and the cost of UFG for each year.

c) The Report on Unaccounted for Gas prepared by ScottMadden Management Consultants was submitted pursuant to OEB direction in its Decision and Order in the MAADs proceeding.[2] Further, The *Report on Unaccounted for Gas* prepared by ScottMadden Management Consultants was also submitted and considered as part of the 2020 Phase 2 Rates Application.[3]

d) The Progress Report on Implementation of ScottMadden Recommendations on Unaccounted for Gas (UFG) was submitted and considered as part of the 2022 Phase 2 Rates Application,[4] and again as part of the 2024 Phase 1 Rebasing Application.[5]

The Unaccounted for Gas Supplemental Progress Report was submitted and considered as part of the 2024 Phase 1 Rebasing Application.[6]

e) The requested conversions are as follows:
- 1 m^3 combusted natural gas = 0.00201 tCO_2e
- 1 m^3 vented natural gas = 0.0180 tCO_2e

The above values were derived using the following inputs, as per provincial and federal reporting requirements for 2023 emissions:
- 100-year global warming potentials from the Fifth Assessment Report (AR5) of the United Nations Intergovernmental Panel on Climate Change (IPCC)
- Enbridge Gas Inc. 2023 average gas composition

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[1] EB-2024-0125, Exhibit D, Tab 1, p. 5.
[2]EB-2017-0306 / EB-2017-0307, Decision and Order, dated August 30, 2018. https://www.rds.oeb.ca/CMWebDrawer/Record/663034/File/document.
[3] EB-2019-0194, *Report on Unaccouted for Gas*, ScottMadden Management Consultants, December 2019,https://www.rds.oeb.ca/CMWebDrawer/Record/664529/File/document.
[4] EB-2021-0148, Exhibit C, Tab 2, Schedule 1. https://www.rds.oeb.ca/CMWebDrawer/Record/728474/File/document.
[5] EB-2022-0200, Exhibit 4, Tab 3, Schedule 1, Attachment 3 https://www.rds.oeb.ca/CMWebDrawer/Record/786109/File/document.
[6] EB-2022-0200, Exhibit 4, Tab 3, Schedule 1, Attachment 4 https://www.rds.oeb.ca/CMWebDrawer/Record/786109/File/document.

- CH_4 and N_2O emission factors for natural gas taken from Canada's Greenhouse Gas Quantification Requirements, Table 2-5, pipelines

Table 1
Historical UAF Volumes for EGI

Line No.	Calendar Year	EGD Rate Zone UAF Volumes (10^3 m^3) (1)	EGD Rate Zone Year-Over-Year Change (%)	Union Rate Zones UFG Volumes (10^3 m^3) (2)	Union Rate Zones Year-Over-Year Change (%)	EGI UFG Volumes (10^3 m^3)	EGI Year-Over-Year Change (%)
1	1991	40,662					
2	1992	66,028	62%				
3	1993	49,782	-25%				
4	1994	108,765	118%				
5	1995	90,655	-17%				
6	1996	56,739	-37%				
7	1997	65,228	15%				
8	1998	116,376	78%				
9	1999	108,201	-7%				
10	2000	132,021	22%				
11	2001	75,606	-43%	184,102		259,708	
12	2002	9,284	-88%	109,542	-40%	118,826	-54%
13	2003	21,412	131%	108,819	-1%	130,231	10%
14	2004	-22,406	-205%	176,650	62%	154,244	18%
15	2005	14,815	-166%	169,540	-4%	184,355	20%
16	2006	10,274	-31%	154,015	-9%	164,289	-11%
17	2007	83,823	716%	203,713	32%	287,536	75%
18	2008	44,424	-47%	143,880	-29%	188,304	-35%
19	2009	110,917	150%	201,845	40%	312,762	66%
20	2010	72,104	-35%	67,283	-67%	139,387	-55%
21	2011	73,355	2%	35,668	-47%	109,023	-22%
22	2012	74,762	2%	68,690	93%	143,452	32%
23	2013	97,361	30%	113,997	66%	211,358	47%
24	2014	135,380	39%	97,109	-15%	232,489	10%
25	2015	88,438	-35%	54,408	-44%	142,846	-39%
26	2016	133,112	51%	131,588	142%	264,700	85%
27	2017	93,077	-30%	108,901	-17%	201,978	-24%
28	2018	142,086	53%	136,447	25%	278,533	38%
29	2019	140,594	-1%	137,652	1%	278,246	0%
30	2020	110,234	-22%	74,120	-46%	184,354	-34%
31	2021	115,553	5%	252,582	241%	368,135	100%
32	2022	256,333	122%	250,692	-1%	507,025	38%
33	2023	79,232	-69%	122,613	-51%	201,845	-60%
34	2024 (3)	157,876	99%	145,044	18%	302,920	50%
35		2,952,103		3,248,900		5,366,546	

Notes:

1 Refer to Exhibit D, Tab 1, Page 6, Table 1. 1991-2023 are utility volumes only. Reported volumes for 2024 are for utility and non-utility. Allocation to non-utility is finalized at year-end.

2 Refer to Exhibit E, Tab 1, Page 27, Table 2. UFG volumes for the years from 1991 to 2000 for the Union rate zones are not available. Reported volumes include utility and non-utility volumes.

3 Total utility and non-utility UFG volumes, based on January to July 2024 actuals and budgeted volumes and cost for August to December 2024

Table 2
Historical UAF Volumes and Costs for EGI

		EGD Rate Zone			Union Rate Zones			EGI	
Line No.	Calendar Year	UAF Volumes (10^3 m^3) (1) (6)	UAF Costs ($) (4)	Average Commodity Costs ($/$10^3$ m^3) (5)	UFG Volumes (10^3 m^3) (2)	UFG Costs ($)	Average Commodity Costs ($/$10^3$ m^3) (5)	UFG Volumes (10^3 m^3)	UFG Costs ($)
1	1991	40,662							
2	1992	66,028							
3	1993	49,782							
4	1994	108,765	13,066,103	120.132					
5	1995	90,655	9,227,372	101.786					
6	1996	56,739	5,461,881	96.263					
7	1997	65,228	6,783,375	103.995					
8	1998	116,376	14,415,282	123.868					
9	1999	108,201	15,511,993	143.363					
10	2000	132,021	25,118,833	190.264					
11	2001	75,606	23,668,988	313.057	184,102	43,265,185	285.112	259,708	66,934,173
12	2002	9,284	2,100,094	226.206	109,542	23,448,730	220.991	118,826	25,548,824
13	2003	21,412	6,238,675	291.364	108,819	31,128,668	284.389	130,231	37,367,343
14	2004	-22,406	-6,840,748	305.309	176,650	56,127,812	308.238	154,244	49,287,064
15	2005	14,815	5,288,525	356.971	169,540	61,469,586	356.671	184,355	66,758,111
16	2006	10,274	5,269,882	411.790	154,015	60,488,681	412.514	164,289	65,758,562
17	2007	83,823	28,054,209	349.590	203,713	70,413,589	353.386	287,536	98,467,798
18	2008	44,424	15,505,857	367.448	143,880	56,241,846	365.733	188,304	71,747,703
19	2009	110,917	28,285,548	277.749	201,845	55,998,867	279.165	312,762	84,284,415
20	2010	72,104	15,819,372	230.219	67,283	17,263,561	242.423	139,387	33,082,932
21	2011	73,355	14,404,450	198.944	35,668	8,028,301	218.754	109,023	22,432,751
22	2012	74,762	12,826,697	167.097	68,690	12,902,646	188.051	143,452	25,729,343
23	2013	97,361	15,785,643	187.261	113,997	22,631,943	206.087	211,358	38,417,586
24	2014	135,380	27,670,458	211.918	97,109	18,429,387	216.502	232,489	46,099,845
25	2015	88,438	18,534,368	202.629	54,408	10,531,568	202.392	142,846	29,065,936
26	2016	133,112	22,368,047	168.233	131,588	24,169,844	178.900	264,700	46,537,891
27	2017	93,077	16,562,841	178.906	108,901	15,707,067	155.664	201,978	32,269,907
28	2018	142,086	23,172,234	160.030	136,447	17,877,943	129.547	278,533	41,050,177
29	2019	140,594	22,872,512	157.562	137,652	16,741,570	132.562	278,246	39,614,083
30	2020	110,234	16,127,918	140.219	74,120	8,408,332	112.035	184,354	24,536,250
31	2021	115,553	21,258,659	171.832	252,582	40,512,883	141.351	368,135	61,771,542
32	2022	256,333	69,720,454	283.709	250,692	75,317,596	258.687	507,025	145,038,050
33	2023	79,232	17,948,507	207.079	122,613	22,518,980	179.355	201,845	40,467,487
34	2024 (3)	157,875	22,134,995	151.717	145,044	21,394,897	139.477	302,919	43,529,892
35	Total	2,795,631	534,363,023		3,248,900	791,019,481		5,366,546	1,235,797,667

Notes:
1 Refer to Exhibit D, Tab 1, Page 6, Table 1. 1991-2023 are utility volumes only. Reported volumes for 2024 are for utility and non-utility. Allocation to non-utility is finalized at year-end.
2 Refer to Exhibit E, Tab 1, Page 27, Table 2. UFG volumes for the years from 1991 to 2000 for the Union rate zones are not available. Reported volumes include utility and non-utility volumes
3 Total utility and non-utility UFG volumes and costs, based on January to July 2024 actuals and budgeted volumes and cost for August to December 2024
4 UAF cost and average commodity cost are not available for 1991 to 1993
5 Simple average of monthly reference price
6 Total is 1994-2024

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1

Question(s):

Please explain the following statement from page 12: “It is reasonable to assume that such trends in UFG volumes or related trends in UFG costs may be reflective of common macroeconomic, geo-political, and/or national/continental weather trends, which have the potential to impact UFG volumes or costs broadly across the industry.

Response:

As stated at Exhibit D, Tab 1, page 14,

> For the purposes of deriving UFG-related costs, UFG volumes are calculated by determining the difference between net gas sendout volumes (Sendout) and actual in-franchise customer consumptions volumes (Consumption). In a theoretical system with no UFG, Sendout volumes would match Consumption volumes.

Demand for natural gas is heavily influenced by factors such as variations in weather, economic growth, the availability of supply, and prices of natural gas.[1] Demand materializes in the form of consumption, which is part of the determination of UFG as noted above. Therefore, factors or trends impacting demand may consequently be reflected in the levels of UFG experienced.

[1] Factors affecting natural gas prices - U.S. Energy Information Administration (EIA).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1

Preamble:

Page 25 states as follows:

> "On a monthly basis, the determination of Sendout includes an entry to record operational blowdowns or flaring associated with compressor facilities as noted in the discussion on Sendout above. By accounting for the volumes associated with these operational blowdowns or flaring, these volumes are removed from Sendout and as such do not contribute to calculated UFG volumes. A similar entry is recorded, where necessary, for blowdowns or flaring associated with capital projects."

Question(s):

a) Please provide a definition of blowdowns. Does it ever include something other than allowing methane to be released to the atmosphere?

b) Please provide a breakdown of the total volumes of blowdowns over the past five years, with a breakdown by type if possible (e.g. compressor related versus capital project related).

c) Please provide a breakdown of the total volumes of flaring over the past five years, with a breakdown by type if possible (e.g. compressor related versus capital project related). If it cannot be differentiated from blowdowns, please provide the total of both.

d) Who pays for the cost of gas released to the atmosphere in blowdowns or flared. If it differs depending on the situation, please describe each relevant situation. Please describe the regulatory mechanism used in each case.

e) Why are blowdowns and flaring associated with compressor facilities not included in UFG?

f) Are the emissions from blowdowns accounted for in Enbridge's climate accounting with respect to its climate targets?

Response:

a) As discussed in the Company's pre-filed evidence,[1] blowdown gas is "…an estimate of volumes typically purged or flared for operational maintenance purposes…".

b) and c)

Please see Table 1 for the total annual blowdown volumes from 2019 to 2023 broken down by type. Flaring volumes are not differentiated from blowdown volumes.

Table 1
Enbridge Gas Historical Blowdown Volumes 2019-2023

Line No.	Calendar Year	Operational Blowdown Volumes (10^3 m^3)	Capital Blowdown Volumes (10^3 m^3)	Total Blowdown Volumes (10^3 m^3)
1	2019	752	421	1,173
2	2020	578	483	1,061
3	2021	1,284	0	1,284
4	2022	651	109	760
5	2023	585	122	706

d) The forecast cost of gas for blowdowns (or flaring) associated with the compressor facilities is recovered from all customers through delivery rates. Any cost variances associated with the costs in rates and the actual costs is at the risk of the shareholder. The actual cost for blowdowns (or flaring) associated with the capital projects is capitalized to the relevant project.

e) As the volumes associated with blowdowns and flaring activities discussed are properly accounted for by adjusting net gas sendout (Sendout) they do not impact the determination of the unaccounted for (UFG) volumes/costs that are the subject

[1] Exhibit D, Tab 1, p. 15, para. 26.

of the current application, which are calculated as the difference between Sendout[2] and Consumption[3] volumes.

f) Yes, blowdown emissions are included within Enbridge Gas's GHG emissions inventory as reported to provincial and federal GHG reporting programs. They are also accounted for within Enbridge Gas's reported emissions in its 2023 Sustainability Report and 2023 ESG Datasheet.

[2] The net volume of natural gas delivered into the Enbridge Gas distribution system to serve in-franchise customer demands after accounting for receipts and deliveries across the Company's integrated storage, transmission, and distribution systems.
[3] In-franchise customer consumption including measured, and estimated volumes and billed, and unbilled volumes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 31-32

Question(s):

a) Please list and define the different classes of leaks.

b) Please provide a table showing the number of leaks of each class in Enbridge's system as of December 31 of each of the last five years and the current number.

c) Please file and describe the "Enbridge Gas Leak Standard."

d) Please provide the calculations underlying the leak loss reductions estimates on page 32.

e) Using the industry-average emissions factors described on page 32, please provide an average estimated m3 lost per leak, and ideally per leak of each class if possible. Please include appropriate caveats.

Response:

a) and c)

Please see the responses at Exhibit I.MC-5 parts a) and b).

b) Table 1 lists the leak classifications identified during above and below ground leak indications since 2019 and includes the current year-to-date numbers for 2024, for each of the EGD Rate Zone and Union Gas Rate Zones.

Table 1
Enbridge Gas Historical Annual Leak Classifications

Line No.	Year	Rate Zone(s)	A	B	C	Unclassified	Total
1	2019	EGD	1,073	415	1	5,461	6,950
2		Union	68	1,027	1,350	8,390	10,835
3	2020	EGD	1,379	502	4	6,686	8,571
4		Union	62	1,380	629	10,477	12,548
5	2021	EGD	1,217	535	50	6,011	7,813
6		Union	207	1,028	872	9,902	12,009
7	2022	EGD	2,586	1,512	456	6,739	11,293
8		Union	640	572	902	5,909	8,023
9	2023	EGD	3,302	1,671	589	8,204	13,766
10		Union	1,357	1,353	792	5,640	9,142
11	2024	EGD	2,456	1,164	454	5,017	9,091
12		Union	1,168	838	453	3,431	5,890
13		Total	15,515	11,997	6,552	81,867	115,931

d) and e)

The emissions reduction estimate related to the reduction of the backlog of leaks was calculated using published industry-average emission factors and activity factors. An emission factor is the typical emission rate for a given component. The activity factor refers to the population of emitting equipment (in this instance, a count of leaks). The backlog of leaks to be eliminated as part of this program, were estimated to have a similar asset distribution to the annual leak distribution.

Calculation:
Estimated Volume Leaked (m^3/year) =
Activity Factor (leak count) x Emission Factor (m^3 natural gas/year/leak)

Please see Table 2 for the detailed calculation of the annual leak loss reduction estimate of approximately 1,100 $10^3 m^3$, resulting from the resolution of the backlog of leaks referenced.

Emissions factors used to calculate volumes lost due to pipeline leaks are based on pipe type and material, not leak class. Thus Enbridge Gas is unable to provide the calculations by leak class as requested. Instead, Table 2 (see “Emission Factor (m^3 natural gas/year/leak)” column) provides the industry-average volume of gas lost per leak by pipe type.

Table 2
Calculation of Estimated Reduction in Gas Losses from Leaks

Line No.	Pipe Type	Activity Factor (leak count)	Industry Average Emission Factor (m^3 CH_4/hr/leak)	Industry Average Emission Factor (m^3 natural gas/year/leak)	Estimated Volume Leaked (m^3/year)
1	Unprotected Steel Main	7	0.068	635	4,000
2	Protected Steel Main	663	0.107	999	663,000
3	Plastic Main	609	0.029	271	165,000
4	Unprotected Steel Service	123	0.029	271	33,000
5	Protected Steel Service	648	0.011	103	67,000
6	Plastic Service	1,150	0.011	103	118,000
7	TOTAL	3,200			1,100,000

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 61

Question(s):

Please provide an updated version of table 11 that provides the annualized cost over the lifetime of the equipment.

Response:

The following response was provided by Highwood Emissions Management:

Aerial and satellite technology providers include the cost of overhead as part of their survey costs. Operators such as Enbridge Gas would not be expected to purchase satellites or aircraft to perform emissions measurement work. The vendors are generally responsible for the equipment's lifetime costs and these are not made public but are instead externalities of their business model that are passed on to the customer (i.e., Enbridge Gas) in the vendor fees. For vehicle and handheld technologies, the same may be true if a third-party service provider is contracted to perform surveys.

The estimated vehicle costs in Table 11, which are based on the costs provided in the Highwood Report,[1] include a capital component which assumes purchase of the equipment. The estimated handheld costs in Table 11, which are based on the costs provided in the Highwood Report,[2] assumes purchase of handheld analyzers as referenced in the Highwood Report.[3] Highwood does not currently have information on the expected lifetime of the equipment. The costs estimated by Highwood did not include operational costs for ground follow-up to classify and repair leaks found as part of the surveys, which can be extremely significant depending on the type of equipment used and the number of leaks found. Highwood developed these cost estimates as a high-level means of comparing between different technologies, with the expectation that if Enbridge Gas moves forward with the recommendations, the Company would refine these estimates based on vendor quotes.

[1] Exhibit D, Tab 1, Attachment 1, p. 76, Table 24.
[2] Exhibit D, Tab 1, Attachment 1, p. 76, Table 24.
[3] Exhibit D, Tab 1, Attachment 1, p. 76, Table 19, Footnote 1; https://carboncontainmentlab.org/documents/methane-measurement-memo-website-version-1671206674.pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 61

Question(s):

a) Please provide a table showing the emissions (CO_2e) arising from all fugitive emissions for each of the past 5 years.

b) Please provide a table showing the emissions (CO_2e) arising from all fugitive emissions and unknown UFG for each of the past 5 years on the assumption that unknown UFG is being leaked.

Response:

a) Table 1 provides the total annual fugitive emissions for the past five years, as reported to the provincial and federal GHG reporting programs.

   As identified at Exhibit D, Tab 1, Attachment 1, Section 7.5, fugitive emissions are attributable to both the storage and transmission operations (STO) and the distribution operations (DO). Over 70% of STO fugitive emissions are calculated using direct measurement.[1] Whereas, DO fugitive emissions are calculated using industry average emission factors resulting in associated potential uncertainty of 118%.[2]

   Enbridge Gas submitted an investigation plan,[3] which proposes to pilot emissions measurement technologies on a portion of the distribution system, in order to improve the accuracy of its DO emissions inventory.

[1] Exhibit D, Tab 1, Attachment 1, p.49.
[2] Exhibit D, Tab 1, Attachment 1, pp.51 and 53.
[3] Exhibit D, Tab 1, Section 4.1, pp.61-64.

Table 1

Historic Calculated Annual Fugitive Emissions

Year	Fugitive Emissions (tCO_2e)
2019	431,523
2020	431,591
2021	445,006
2022	439,703
2023	407,683

b) For estimated annual emissions (tCO_2e) arising from all calculated fugitive emissions for the last 5 years, please see the response to part a) above. For quantification of investigated sources of UFG please see the response at Exhibit I.STAFF-7 part d). A similar list, summarizing all contributing sources of UFG discussed in the Company's pre-filed evidence categorized according to whether they relate to emissions or not, is set out in the response at Exhibit I.MC-1 parts d) and f).

In natural gas systems, UFG is the difference between the measured gas volumes delivered into the system (defined as net gas sendout or Sendout volumes for the purposes of the current Application)[4] and the measured gas volumes exiting the system (defined as in-franchise customer consumption or Consumption volumes for the purposes of the current Application)[5].

The assumption that all "unknown UFG" represents physical gas loss which is leaked to the atmosphere is not reasonable. As stated in the Company's pre-filed evidence,

> The residual difference between Sendout and Consumption represents a combination of actual physical gas losses/gains as well as temporary variances resulting from estimation used in both the billing and accounting processes described….[6]

Said differently, fugitive emissions make up just one of several potential contributors to UFG and are limited specifically to the unintended releases of gases from equipment leaks and third-party damage events. As explained in the response at Exhibit I.MC-1 parts d) and f), the majority of contributing sources identified, investigated, and quantified[7] do not represent any form of physical gas loss leaked to atmosphere.

CO_2e is a metric that is used to compare the warming effect of various greenhouse gas emissions in the atmosphere to the equivalent amount of carbon dioxide that

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[4] Exhibit D, Tab 1, pp.14-16.
[5] Exhibit D, Tab 1, pp.16-25.
[6] Exhibit D, Tab 1, p.25.
[7] Exhibit I.STAFF-7 part d).

would produce a similar warming effect. UFG can and does exist without any gas entering the atmosphere and therefore it is not appropriate to express all “unknown UFG” volumes as emissions (CO_2e) as requested.[8]

[8] Please see Exhibit D, Tab 1, Sections 1.3, 1.4, 2, and 3 for discussion on non-emissions related UFG investigations which are also summarized in the response at Exhibit I.STAFF-7 part d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 61

Question(s):

a) Please provide a table showing the cost arising from all known fugitive emissions for each of the past 5 years.

b) Please provide a table showing the cost of all fugitive emissions and unknown UFG for each of the past 5 years.

Response:

a) Accurately calculating the specific costs of fugitive emissions or any other contributing sources of UFG is extremely complex and time consuming. Therefore, in Table 1, Enbridge Gas has produced a simplified illustrative example estimating historical UFG costs related to fugitive emissions by applying a calculated ratio (annual reported fugitive-emissions related volumes vs. total annual UFG volumes) to total annual UFG costs.[1]

Table 1
Estimated Annual UFG Costs Associated with Fugitive Emissions

Year	Estimated Fugitive Costs ($ Millions)
2019	3.9
2020	3.6
2021	4.7
2022	7.0
2023	4.5

[1] Please see the responses at Exhibit I.ED-4 parts a) & b), for historical UFG volume and cost details. Please also see the responses at Exhibit I.STAFF-13, for discussion regarding the impact of lower gas supply commodity costs in 2023 vs. 2022.

b) Please see the response to part a) above, for discussion regarding volumes and costs associated with fugitive emissions. As stated, accurately calculating the specific costs of fugitive emissions or the volumes and costs associated with unknown sources of UFG as requested requires a complete investigation (including regarding their related ranges of uncertainty)[2]. Accordingly, the Company is unable to accurately estimate "unknown" UFG volumes and costs at this time.

As noted in the response at Exhibit I.MC-2 part b), Enbridge Gas does not yet possess a comprehensive and accurate understanding of the specific historic annual impacts (volumetric or cost) of all potential contributing sources of UFG (known or unknown sources). However, the Company has formed a UFG team to identify, investigate, and mitigate contributing sources of UFG and to develop long-term and sustainable governance, monitoring and reporting.

For details regarding aggregated costs associated with total UFG volumes annually, please see the response at Exhibit I.ED-4 part b). For details regarding best estimates of the historic volumetric impacts of select contributing sources of UFG investigated since the UFG team's formation, please see the response at Exhibit I.STAFF.7 part d).

[2] Exhibit D, Tab 1, p. 8.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 61

Question(s):

a) Please provide a table showing, for each of the past ten years, Enbridge's total UFG (m^3) and as granular a breakdown by source/cause (m3), including a column for "unknown" source.

b) Please provide a description of each source/cause listed in the table above, what it includes, and how it is estimated.

c) Please provide a version of the table described in (a) which provides the breakdown by source as a percentage of the total UFG.

Response:

a) - c)

Please see the response at Exhibit I.STAFF-7 part d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 62

Question(s):

a) For each item described in paragraph 122, please provide an estimated start date and completion date.

b) When will the technology pilot be complete?

c) When does Enbridge plan to roll out the measurement program based on the pilot?

Response:

a) and b)

Pending OEB approval of Enbridge Gas's proposed Fugitive Emissions Measurement Administration Deferral Account (FEMADA), the timeline set out in Table 1 is proposed for the Investigation Plan discussed in Exhibit D, Tab 1, paragraph 122. These timelines represent the Company's current best estimates and may change as required.

Table 1
Proposed Fugitive Emissions Investigation Plan Timeline

Piloting development of company-specific EFs on a subset of assets.	Jan - Dec 2025
Piloting a mobile ground (vehicle) technology on a limited portion of the distribution system	Jan - Dec 2025
Begin configuration and assessment of IT systems	Apr - Dec 2025
Continue monitoring developments in aerial and satellite technologies	May 2024 - onwards

c) Enbridge Gas's current greenhouse gas emissions accounting and reporting methodologies, which use a combination of direct measurement and published emission factors, are compliant with applicable Canadian regulatory requirements and are done in accordance with industry standard practices. Measurement data collected during pilot studies can start to be incorporated into Enbridge Gas's reported emissions inventory upon their completion, pending the results of the pilot.

Roll out of a full system measurement program will depend on the outcomes of the proposed pilot, scale-up feasibility, OEB approvals, and potential future provincial and federal regulatory requirements.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, attachment 1

Question(s):

Please file a copy of the Clearstone study referred to on page 53 of attachment 1.

Response:

Please see Attachment 1 for a copy of the Clearstone Engineering Ltd. 2021 Uncertainty Analysis.

CLEARSTONE ENGINEERING

19 September 2021

ENBRIDGE GAS INC.
50 Keil Drive North
Chatham, Ontario
N7M 5M1

Attention: Peter Mussio

Reference: 2021 Uncertainty Analysis

Dear Mr. Mussio:

Table 1 below summarizes the estimated uncertainty in the reported 2020 GHG emissions from Enbridge Gas Inc.'s Ontario operations. The GHG emissions and uncertainties are summarized by type of GHG (i.e., CO_2, CH_4, and total CO_2e) and primary source category (i.e., venting, flaring, fugitive sources and fugitive). Additionally, the contributions for non-fuel use activities are disaggregated by industry segment (i.e., transmission, storage, LNG and distribution). The total emissions amount to 489,797 tonnes of CO_2e and have an uncertainty of ±32.5%. The fugitive contributions from distribution facilities contribute most to this uncertainty. Those contributions are primarily from leaking buried pipe and leaks from commercial and industrial meter sets.

The presented uncertainties were assessed by assigning uncertainty values to all calculation parameters and activity data applied in the Enbridge GHG calculation spreadsheets, and applying an IPCC Tier 1 uncertainty propagation analysis. The uncertainty propagation procedures have been implemented in a copy of the spreadsheets used by Enbridge to develop its GHG emissions inventory. Copies of the spreadsheets are included with this letter and comprise the following files:

- TOTAL Emissions.xlsx
- Combustion Emissions.xlsx
- Flaring Emissions.xlsx
- Fugitives and Venting.xlsx

The spreadsheets allow a more detailed examination of the uncertainty at different levels of aggregated.

The uncertainties applied to the activity data and emission factors are based on the following assumptions:

- Individual metered gas volumes have an uncertainty ±3%.
- Individual flare gas volumes are based on engineering estimates and have an uncertainty ±25%.
- Individual emission values quantified as part of leak detection and repair surveys have an accuracy of ±15%.
- All counting values and time measurements have an uncertainty of ±5%.
- All compositions have an uncertainty of ±5%.
- The uncertainties of all the applied emission factors either are referenced from the CEPEI Methodology Manual or, in the absence of such values, are estimated based on engineering judgement.

In all cases, the applied uncertainties account for the combined effect of measurement inaccuracies, the variability of a given source with time, and variability between sources.

Please contact me if you have any questions or concerns regarding the presented information.

Thank you.

Yours truly,
CLEARSTONE ENGINEERING LTD.

David Picard

David J. Picard, M.Eng., P.Eng.
President

Table 1: Summary of the 2020 GHG emissions from the Ontario operations of Enbridge Gas Inc., and the estimated uncertainty in these values.

Emissions Breakdown	CO_2 (tonnes)	Uncertainty (Fractional)	CH_4 (tonnes)	Uncertainty (Fractional)	N_20 (tonnes)	Uncertainty (Fractional)	CO_2e (tonnes)	Uncertainty (Fractional)
Transmission								
Venting	19.3	0.085	3,009.7	0.085	0.0	0.000	75,262.5	0.085
Flaring	2,011.4	0.102	5.5	0.119	0.0	0.721	2,164.0	0.095
Fugitive	2.6	0.082	387.9	0.082	0.0	0.000	9,699.9	0.082
Sub-Total	2,033.3	0.101	3,403.2	0.075	0.0	0.721	87,126.4	0.074
Storage								
Venting	4.7	0.184	737.9	0.184	0.0	0.000	18,452.5	0.184
Flaring	35.2	0.050	0.1	4.867	0.0	0.709	37.9	0.315
Fugitive	2.1	0.031	334.4	0.031	0.0	0.000	8,360.9	0.031
Sub-Total	42.1	0.047	1,072.4	0.127	0.0	0.709	26,851.3	0.127
LNG								
Venting	4.4	0.202	681.2	0.202	0.0	0.000	17,035.0	0.202
Flaring	0.0	0.000	0.0	0.000	0.0	0.000	0.0	0.000
Fugitive	0.2	0.139	30.6	0.139	0.0	0.000	765.9	0.139
Sub-Total	4.6	0.193	711.9	0.193	0.0	0.000	17,800.9	0.193
Distribution								
Venting	2.1	3.086	329.0	3.086	0.0	0.000	8,226.3	3.085
Flaring	0.0	0.000	0.0	0.000	0.0	0.000	0.0	0.000
Fugitive	361.0	1.687	5,309.3	1.179	0.0	0.000	133,093.5	1.176
Sub-Total	363.1	1.677	5,638.3	1.125	0.0	0.000	141,319.8	1.122
Fuel Combustion								
Fuel Use	209,836.8	0.015	209.6	1.770	5.4	1.520	216,699.4	0.045
Sub-Total	209,836.8	0.015	209.6	1.770	5.4	1.520	216,699.4	0.045
TOTAL	212,279.8	0.015	11,035.2	0.576	5.5	1.507	489,797.7	0.325

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, attachment 1

Question(s):

These questions are for Highwood

a) Page 59 states that "a vehicle-mounted advanced mobile leak detection (AMLD) system, capable of detecting and quantifying leaks, was piloted in 2023." What were the learnings from that pilot?

b) Why would Enbridge need to run another vehicle-mounted leak detection pilot?

c) Approximately how many kms of distribution pipelines does Enbridge own in Ontario?

d) Approximately how many kms of distribution pipelines does Enbridge test for leaks with on-site methane measurements each year?

e) Approximately how many meters does Enbridge own in Ontario?

f) Approximately how many meters does Enbridge test for leaks with on-site methane measurements each year?

g) How are DO emissions calculated using generic EFs? Please provide 4 examples for the 4 most typical leak types or sizes.

Response:

The following response was provided by Enbridge Gas:

a) and b)

The pilot discussed on page 59 of the Highwood Report was focused on leak detection only (i.e. finding leaks). Additionally, this pilot was applied to a limited scope of the distribution system. Enbridge Gas has tested this equipment in the past for leak detection in addition to walking surveys. Highwood has recommended a pilot that focuses both on detection and quantification of leak rate.

The following response was provided by Highwood Emissions Management:

a) and b)

The original pilot was only a brief test that was performed on 27 kilometers of pipeline. Highwood is suggesting an expanded pilot to cover hundreds or thousands of kilometers of pipeline. Furthermore, the original pilot was focused on leak detection (i.e. finding leaks). We recommend a pilot that focuses both on detection and quantification of leak rate.

The following responses were provided by Enbridge Gas:

c) Enbridge Gas owns and operates approximately 140,000 kms of distribution mains and services in Ontario.

d) Enbridge Gas surveys approximately 20,000 km of distribution mains and 800,000 services each year.

e) Enbridge Gas has approximately 3.9 million meters installed in Ontario.

f) Enbridge Gas tests each meter connected to the approximately 800,000 services it surveys each year. A service may be one meter (typical residential service) or multiple meters (small commercial plazas, townhomes, semi-detached) depending on the original installation and requirements of the customer.

g) DO emissions due to leaks are calculated using published industry-average EF in conjunction with activity factors, in compliance with provincial GHG regulatory reporting requirements. An EF is the typical emission rate for a given component or asset.

Calculation:
Leaked Volume (m^3/year) =
Activity Factor (count) x Emission Factor (m^3 natural gas/year/count)

Leaked Emissions (tCO_2e) =
Volume Leaked (m^3/year) x [(mol fraction CO_2 x density CO_2 (t/m^3) x $GWPCO_2$) + (mol fraction CH_4 x density CH_4 (t/m^3) x $GWPCH_4$)]

Example 1 – Commercial Meter Sets

Table 1

Line No.	Component Type	Industry Average Component Count	Emission Factor (kg THC/h/ source)	Emission Factor (m^3 natural gas/ year/component)	Emission Factor (m^3/year)
1	Connectors	47.9	6.561E-05	8.2E-01	3.9E+01
2	Control Valves	0	5.132E-04	6.4E+00	0.0E+00
3	Open-Ended Lines	0	3.490E-02	4.4E+02	0.0E+00
4	Pressure-Relief Devices	1.5	4.971E-04	6.2E+00	9.3E+00
5	Pressure Regulators	1.3	9.782E-05	1.2E+00	1.6E+00
6	Block Valves	7	8.699E-05	1.1E+00	7.6E+00
7	Orifice Meters	0	4.250E-02	5.3E+02	0.0E+00
8	Other Flow Meters	1	7.548E-05	9.4E-01	9.4E-01
9	Commercial Meter Set EF (m^3/year/meter)				5.9E+01

NOTES:
Emission Factors from: Canadian Energy Partnership for Environmental Innovation (CEPEI), Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, prepared by Clearstone Engineering Ltd., 2023, Calculation Form 22.6-32

Example 2 – Residential Meter Sets

Table 2

Line No.	Component Type	Industry Average Component Count	Emission Factor (kg THC/h/ source)	Emission Factor (m^3 natural gas/ year/component)	Estimated Volume Leaked (m^3/year)
1	Connectors	9.6	3.624E-06	4.5E-02	4.4E-01
2	Control Valves	0	1.006E-02	1.3E+02	0.0E+00
3	Open-Ended Lines	0	3.490E-02	4.4E+02	0.0E+00
4	Pressure-Relief Devices	0	1.749E-03	2.2E+01	0.0E+00
5	Pressure Regulators	0.9	1.761E-05	2.2E-01	2.0E-01
6	Block Valves	1.1	1.272E-05	1.6E-01	1.7E-01
7	Orifice Meters	0	4.250E-02	5.3E+02	0.0E+00
8	Other Flow Meters	1	3.962E-06	4.9E-02	4.9E-02
9	Residential Meter Set EF (m^3/year/meter)				8.6E-01

NOTES:
Emission Factors from: Canadian Energy Partnership for Environmental Innovation (CEPEI), Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, prepared by Clearstone Engineering Ltd., 2023, Calculation Form 22.6-33

Example 3 – Leaking Buried Pipe (Service Lines)

Activity Factor =
Total Equivalent Leaks = [(OL + LI) – 0.5 x RL] + (UDL + URL),

Where:

- OL = Outstanding Leaks at the beginning of the year (i.e. leaks that are found in a prior year and not yet repaired)
- LI = Leak Indicators (i.e. new leaks identified during the year, including those from call-ins)
- RL = Repaired Leaks
- UDL = Undetected Leaks (0.15 x LI)
- URL = Unreported Leaks (i.e. leaks which occur in parts of the system that were not surveyed during the given year (function of # of years since last survey))

Table 3

Line No.	Pipe Type	Emission Factor (m^3 CH_4/hr/leak)	Emission Factor (m^3 natural gas/year/leak)
1	Unprotected Steel Service	0.029	271
2	Protected Steel Service	0.011	103
3	Plastic Service	0.011	103

NOTES:
Emission Factors from: Canadian Energy Partnership for Environmental Innovation (CEPEI), Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, prepared by Clearstone Engineering Ltd., 2023,
(a) Unprotected Steel Service: Calculation Form 4.2.1-9
(b) Protected Steel Service: Calculation Form 4.2.1-8
(c) Plastic Service: Calculation Form 4.2.1-7

Example 4 – Gate Station Leaks

Table 4

Line No.	Component Type	Company Average Component Count	Emission Factor (kg THC/h/ source)	Emission Factor (m^3 natural gas/ year/component)	Estimated Volume Leaked (m^3/year)
1	Connectors	473	1.470E-04	1.8E+00	8.7E+02
2	Control Valves	1	5.630E-03	7.0E+01	7.0E+01
3	Open-Ended Lines	0	3.490E-02	4.4E+02	0.0E+00
4	Pressure-Relief Devices	3	5.040E-04	6.3E+00	1.9E+01
5	Pressure Regulators	5	1.400E-03	1.7E+01	8.7E+01
6	Block Valves	49	5.670E-04	7.1E+00	3.5E+02
7	Orifice Meters	1	4.250E-02	5.3E+02	5.3E+02
8	Other Flow Meters	1	3.280E-03	4.1E+01	4.1E+01
9	Total (m^3/year/station)				2.0E+03

NOTES:
Emission Factors from: Canadian Energy Partnership for Environmental Innovation (CEPEI), Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, prepared by Clearstone Engineering Ltd., 2023, Calculation Form 22.6-28

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, attachment 1

Question(s):

These questions are for Highwood

a) Page 59 states: “Annual leak surveys are performed on a portion of distribution assets, covering about one-fifth of the system yearly.” Page 62 states: “The current LDAR program is based on historic practices of surveying approximately 1/7th of the infrastructure each year using handheld portable gas monitors on foot (in rural areas, operators drive with gas monitors).” Please reconcile the statements.

b) Page 62 states: “The current LDAR program is based on historic practices of surveying approximately 1/7th of the infrastructure each year using handheld portable gas monitors on foot (in rural areas, operators drive with gas monitors).” Please describe how this is accomplished physically. Does a person literally walk or drive along all segments of a pipeline at a slow enough speed to measure methane? Does this include pipelines that are not along roads (e.g. through fields)?

c) What are the types of leaks or location of leaks most likely missed with the handheld every 7 years approach discussed on page 62?

d) Page 62 states: “Detected leaks are evaluated and assigned a relative risk level (safety), which is how repairs are triggered.” How are leaks assigned a relative risk without there being any measurements? What information is used to characterize the leaks?

e) How would a vehicle survey cover portions of pipelines that are not along roads?

<u>Response:</u>

The following responses were provided by Highwood Emissions Management:

a) These ratios are a high-level average representation of survey frequency used in modelling. Different individual assets are surveyed at different frequencies based on regulatory requirements and the type of asset being surveyed. The 1/5th ratio is a high-level estimate reflecting Enbridge Gas's current work practice, while the 1/7th ratio is a high-level estimate of the historic ratio. Highwood and Enbridge Gas agreed that the 1/7th ratio was still fair to use as a modelling parameter as it would be a more conservative estimate since it assumes less annual system coverage.

e) Most distribution lines tend to be near roads. Emissions from pipelines that are outside the field of view of a mobile sensor would not be covered by a vehicle survey. However, vehicles are instrumented with extremely sensitive sensors that can often detect emissions tens or even hundreds or meters downwind of a source. Operators should track any pipeline segments that would not be covered by a vehicle-based survey, whether due to wind direction, vehicle access, or other factors. Some vendors may provide this service.

The following responses were provided by Enbridge Gas:

b) As discussed in the Highwood Report,[1] annual distribution leak surveys are performed on a portion of the distribution assets, utilizing a combination of walking and mobile surveys.

   To complete the walking survey, the surveyor must walk as close as practical to being centred on the pipeline. While walking they will sweep their probe covering a corridor 1.5 m wide. This includes pipelines in fields and right of ways.

   Mobile surveys are completed by driving directly over or immediately adjacent to the pipeline. Leak indications detected by the mobile system are subsequently investigated using leak survey walking methods. The existing Enbridge Gas distribution leak survey program utilizes technologies that can detect the presence of a leak, but are not capable of quantifying the leak rate.

c) Distribution assets are surveyed in accordance with CSA Z662 leak management requirements and Enbridge Gas remains confident in the leak survey program. If a leak were to form after the leak survey was performed and before the next survey took place, Enbridge Gas has other measures in place to protect public safety, such as, odorization and education campaigns, as per regulations.

[1] Exhibit D, Tab 1, Attachment 1, p. 58.

d) Leaks are evaluated and assigned a risk relative risk level based on the following considerations. The potential for these five factors to create a hazardous condition must be evaluated when establishing the leak classification and associated response requirements.

1. Concentration of the leak/odour and sound/soap test
2. Asset information (age, condition, fittings, material, coating type, etc.)
3. Spread of the leak and the potential for further migration into buildings and below-grade structures
4. Location of the leak in proximity to buildings, other utilities, and other below grade structures
5. Soil type and surface conditions which may promote subsurface migration

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, attachment 1

Question(s):

These questions are for Highwood

a) Please reproduce the chart on page 77 with the annualized costs based on the lifetime of the equipment.

b) Please provide a table showing the typical detection thresholds of the various detection methods with stated assumptions on factors such as speed, temperature etc.

c) Please provide a table the range of detection thresholds of the various detection methods (i.e. high and low).

d) For the figures shown on pages 79 to 82, do the percentages represent the number of leaks detected or the cubic meters of leaks that are stopped. If it is the number, please reproduce the figures with weighting by leak size.

e) Please discuss the effectiveness of tower-based monitoring for urban areas.

f) Page 89 describes the current method as "handheld walking survey using detection only gas analyzer." How does the modelled handheld approach differ in terms of equipment, steps taken, and detection threshold.

Response:

The following responses were provided by Highwood Emissions Management:

a) Please see the response at Exhibit I.ED-8.

b) A table including detection thresholds for various technologies was provided in the Appendix to the Highwood report (Please see Exhibit D, Tab 1, Attachment 1, p.104-

112). The detection thresholds that were used for LDAR-Sim Modelling were outlined in the Highwood Report (Please see Exhibit D, Tab 1, Attachment 1, p.68).

The referenced thresholds were based on a combination of vendor specifications, controlled release data (where available), and company information (where available). The following represents standard testing conditions for controlled release tests.

Technology Class	Screening Altitude	Travel Speed	Temperature Range	Sources
Satellite	512km - 550 km	Orbital period of 95 minutes with 15 orbits per day	15 – 25° C	Speed and Altitude
Aerial	150m – 3000m	~160 km/hr (typical flight speed of a Cessna type fixed-wing aircraft, the typical platform)	15 – 25° C	Altitude 1 Altitude 2 Flight Speed 1 Flight Speed 2
Vehicle	NA	50 km/hr – 80 km/hr (typical driving speed)	15 – 25° C	Typical driving speeds referenced.
Handheld	NA	NA (operator is stationary when taking measurements)	15 – 25° C	

c) Please see table below for the range of detection thresholds of the various detection methods.

Technology Class	Detection Range (CH_4)	Sources
Aerial	0.5 kg/hr – 10 kg/hr	Low End High End
Satellite	42 kg/hr – 1000 kg/hr	Low End High End
Vehicle	0.0057 kg/hr – 1 kg/hr	PoMELO Testing
Handheld	<0.03 kg/hr – 0.57 kg/hr	OGI Detection Paper

d) These figures show the un-weighted leak count. Emissions mitigation plots are shown in the Appendix (Please see Exhibit D, Tab 1, Attachment 1, pp.113-116). These emissions mitigation plots provide a visualization of weighted leak count as a percentage, and account for the emissions size of each leak mitigated in the various modeled scenarios. The baseline scenario modeled in LDAR-Sim represents a program devoid of any formal LDAR. So, the modeled scenarios show mitigation relative to this non-LDAR baseline scenario. Highwood strongly recommends using LDAR-Sim as a heuristic tool to compare program effectiveness, not for accurate emissions accounting. This is why we have elected to not show emission / emissions mitigation volumes (although they do form the background of all calculations). This is because of the heavy assumptions we frequently must make around emissions characteristics, both in terms of frequency and size. However, accepting these assumptions and uncertainties as consistent across the various scenarios allows us to use LDAR-Sim as an effective comparison tool.

e) Recent academic studies have reported on the use of eddy covariance (Stichaner et al., 2024) and dense tower networks (Karion et al., 2023) for quantifying regional scale urban methane emissions. However, these approaches are novel, academic, and based on the methods used and our familiarity with their application, appear to be expensive. The high cost would be expected in part due to the density of expensive sensors required, but more importantly due to the cost of what appears to be extensive data analysis by leading scientists. Another challenge associated with tower-based monitoring is disaggregating source category contributions, such as biogenic emissions from human waste. In the future, it could be that tower-based systems are used in providing urban top-down estimates for reconciliation. At this time, we would consider the solution to be pre-commercial. Highwood is not aware of any natural gas distribution companies leveraging tower-based measurements for leak detection or methane quantification at this time.

f) EGI currently conducts leak surveys on the distribution system without quantifying leak flow rates. The handheld scenario modelled a detection only gas analyzer and assumed that quantification was carried out using a Hi-Flow sampler, assuming perfect quantification performance (no under or over quantification).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1,

Question(s):

These questions are for Highwood and Enbridge

a) Please see page 6 of this report: Hemati M, Mahdianpari M, Nassar R, Shiri H, Mohammadimanesh F. *Urban methane emission monitoring across North America using TROPOMI data: an analytical inversion approach*. Sci Rep. 2024 Apr 19;14(1):9041.[1] Please confirm that it estimates that the methane emissions in Toronto are much higher (230.52) than those measured according to inventories (82.28).

b) Please compare the results from the report in (a) with Enbridge data.

c) This report estimates the emissions from pipelines in Toronto: *Investigation of the Spatial Distribution of Methane Sources in the Greater Toronto Area Using Mobile Gas Monitoring Systems*.[2] Please compare the results with Enbridge data.

d) Does Highwood believe those papers to be authoritative?

e) Please file a copy of those papers so they can be referred to on the record.

Response:

The following responses were provided by Highwood Emissions Management:

a) The referenced paper generally found reported emissions in Toronto to be larger than in the inventories used for comparison. However, certain suburban areas in Toronto were found to have a scale factor below 1, meaning the prior inventory was

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[1] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC11031598/pdf/41598_2024_Article_58995.pdf
[2] https://pubs.acs.org/doi/10.1021/acs.est.0c05386

found to be overestimating methane emissions in those areas. It should be pointed out that this study does not distinguish between emissions from different sectors, see “Due to the low resolution of the Integrated Methane Inversion (IMI) results and co-location of different sources, the posterior results from different sectors are not reported. Sectoral estimates are also more uncertain than the total methane emissions, and the sectoral uncertainties are difficult to quantify”. Therefore, this does not provide any indication of what proportion of measured emissions could be from natural gas distribution activities, customer activities, landfills, agriculture activities, or other sources. Landfills have recently been shown to have much higher emissions than originally thought. In fact, the study cited in the response at Exhibit I.ED-17 part c), found the waste sector to be the largest emitter of methane in the Greater Toronto Area.

b) The report focused on applying machine learning (Bayesian inversion using the cloud-based IMI framework) to update bottom-up inventories using methane concentrations collected from TROPOMI satellite and the original bottom-up (posterior) assumptions. Without the spatial resolution discussed the response to part a) above, Highwood cannot reliably say which sector (if any) is most notably contributing to the underestimation of emissions. It is for these reasons that Highwood recommended that Enbridge Gas proceed with piloting measurement technologies with lower detection thresholds and higher sensitivities (mobile ground labs and handheld), compared to satellites, that should more reliably be able to identify emissions attributable to Enbridge Gas’s distribution system.

c) Emission rates collected in this paper are from vehicle and bicycle mounted sensors which measure mixing ratios, which are then used in gaussian plume modelling to estimate emission rates. The use of vehicles to measure natural gas distribution leaks is in line with recommendation 2 made in the Highwood Report. It is expected that vehicles should have higher sensitivities and would be able to detect smaller leak sizes typical of distribution operations. The study reports that between 4 and 22 leaks per 100 km were found from the distribution network in downtown Toronto but acknowledges the difficulty in confidently attributing these sources to the distribution network as opposed to other sources. Without confident source attribution, it would be challenging to compare data from the study to Enbridge Gas’s data. It is for this reason that Highwood recommended that Enbridge Gas conduct a vehicle pilot in order to measure leaks arising from their distribution network.

d) Highwood believes these papers to be credible. The methods used are consistent with those often used for estimating methane emissions. Crucially, both papers acknowledge the challenges with source attribution. It is important to note that most atmospheric methane measurement techniques, including satellites and mobile sensors, generally rely on gaussian plume modelling to arrive at emissions flow rates, as opposed to direct measurement techniques such as Hi-Flow samplers or calibrated bagging. Plume modeling introduces a level of error/uncertainty in emissions measurements depending on the accuracy of the models in given field conditions. Both papers are peer reviewed in a credible journal. It is a credible account of methane emissions over a specific period of time but cannot be used to infer anything about emissions from Enbridge Gas. Satellite technologies are generally less sensitive and better suited for global or regional emissions estimates while vehicle and handheld technologies can achieve resolutions that would be more appropriate for measuring natural gas distribution emissions. As noted in the Highwood Report,[3] these technologies are continually evolving and capabilities may change in the future.

e) In order to be responsive, Highwood has reviewed the suggested papers and provided high-level commentary on them. Enbridge Gas chooses not to file these papers as they are not part of the Enbridge Gas evidence within this case, nor should they be adopted as such. The papers are available at the internet locations noted in ED's question and reproduced above at footnotes 1 and 2 from the ED interrogatory.

[3] Exhibit D, Tab 1, Attachment 1, p. 100.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, attachment 1

Preamble:

These questions relate to the following paper: *Majority of US urban natural gas emissions unaccounted for in inventories.*[1]

Question(s):

These questions are for Highwood

a) Please describe the paper's findings as they relate to emissions of un-combusted natural gas in cities.

b) How would Highwood recommend that Enbridge overcome the undercounting of natural gas emissions discussed in this paper?

c) Does Highwood believe this paper to be authoritative?

d) Please file a copy of this paper so it can be referred to on the record.

e) Page 93 of the Highwood study states: "As previously mentioned, the LDAR-Sim results must be caveated that the outputs are reflective of the inputs. Due to the lack of directly measured leak rates from EGI's distribution system, Highwood used literature values as inputs into the simulations. While those literature values were obtained through large-scale measurement campaigns on North American gas utility systems, and the results of the studies were either peer-reviewed or in pre-print review, there is a possibility that the LDAR-Sim results are not representative of EGI's actual leak profile." How would a general undercounting of natural gas emissions in impact the LDAR-Sim results?

[1] https://www.pnas.org/doi/full/10.1073/pnas.2105804118

f) Please provide an description of how the LDAR-Sim results would change if the inputs were adjusted to reflect the findings of the paper noted above (i.e. the emissions were assumed to be higher).

g) Please discuss the possibility of using tower, aerial, or satellite

Response:

The following responses were provided by Highwood Emissions Management:

a) The study is summarized appropriately in the paper's abstract: "Methane emissions from distribution and end use of natural gas (NG) are not well known. We analyzed atmospheric methane measurements to quantify NG emissions in the Boston area over ~8 y, finding NG emissions approximately three times larger than calculated by usage-based inventories. We observed no change in emissions over 8 y despite efforts from the state to address NG pipeline leaks. Seasonal emissions are directly related to consumption of NG, implying that sources other than pipelines, such as transmission and appliances, are important and may require future policy action. We estimate total supply chain losses of 3.3 to 4.7% for NG consumed in urban areas, which significantly increases the climate impacts of NG compared to Environmental Protection Agency estimates."

b) This question assumes that the "undercounting" of emissions observed in the cited study in Boston relative to measurements would be similarly observed in Enbridge Gas's emissions. This assumption is not valid. Highwood has worked with natural gas distribution companies whose measured emissions are higher than inventory estimates and others whose measured emissions are lower than inventory estimates. There are a number of potential explanations for the observations in the cited study. Boston has appeared in other academic studies as a city with anomalously high natural gas loss rates from the natural gas distribution system due to relatively old infrastructure. Another potential reason for underestimation in Boston could be due to company operational practices. These practices can differ significantly between companies and would influence how a given company's reported emissions compare to published inventories. Lastly, the inventory used for comparison in Boston or elsewhere in the US is not directly applicable to locations in Canada. Applicable regional emissions measurement data and company inventories would need to be compared in order to evaluate whether a discrepancy exists between current Company reported emissions and top-down measurements, before any recommendation can be made on how or whether to address discrepancies, should they exist. It is for this reason that Highwood recommended in the Highwood Report that Enbridge Gas conduct handheld and vehicle emissions measurement pilots to obtain company-specific emissions information for their system in order to improve their emissions inventory.[2]

c) The paper is peer reviewed and credible for the context in which the study was performed. However, it should not be assumed that discrepancies observed in Boston are representative of those that might be observed in Canada or for Enbridge Gas.

e) Potential undercounting would impact the LDAR-Sim parameter “emissions production rate” which informs the probability that a leak arises at a site (in this case, km of pipeline) on a given day in the simulation. If we were to hold our assumptions around leak size consistent but assume we had undercounted the number of leaks, we would expect to see increased emissions mitigation from some technology scenarios, but not all. For example, with its very sensitive detection threshold, the modeled handheld technology is expected to be able to detect and ultimately mitigate more of the emissions, according to the simulation. Conversely, the satellite method, which was not capable of detecting any emissions in the simulation, would lag even further behind the more sensitive technologies as there would be more leaks in the simulation (and therefore, more overall emissions) which it cannot detect.

f) A key behavior in LDAR-Sim is the interplay between the parameters which dictate emissions (emissions frequency, emissions size) and those which dictate technology detection performance (detection threshold, screening frequency). Holding the parameters which dictate technology detection performance consistent, increasing the emission sizes in simulations would lead to both greater mitigation and greater emissions. Emissions mitigation would be expected to increase as there would be more emissions in the simulation which are larger than the detection threshold of the modeled technologies.

g) Tower systems are discussed in the response at Exhibit I.ED-18 part e). Aerial and satellite systems are discussed and modeled extensively throughout the Highwood Report.[3]

To summarize, satellite systems are not currently sufficiently sensitive to detect emissions from Enbridge Gas’s distribution assets. Aerial systems also have higher detection thresholds compared to handheld and vehicle technologies, and while they may be sufficiently sensitive to detect larger distribution leaks they have not been deployed extensively to monitor urban natural gas leakage. We recommend that Enbridge Gas monitors advances in aerial and satellite performance. Aerial technology, especially helicopters, is more likely to be

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[2] Exhibit D, Tab 1, Attachment 1, p.95.
[3] Exhibit D, Tab 1, Attachment 1.

effective than satellites in the near term, and Enbridge Gas may eventually consider a helicopter system pilot.

The following response was provided by Enbridge Gas:

d) In order to be responsive, Highwood has reviewed the suggested paper and provided high-level commentary. Enbridge Gas chooses not to file this paper as it is not part of Enbridge Gas's evidence within this case, nor should it be adopted as such. The paper is available at the internet location noted in ED's question and reproduced at footnote 1 from the ED interrogatory.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, attachment 1

Question(s):

These questions are for Highwood.

Page 95 includes 4 recommendations. Please provide a reasonable estimate of how long would be needed for recommendations 1, 2, and 3.

Response:

The following response was provided by Highwood Emissions Management:

Recommendation 1: Approximately 6-18 months from pilot kickoff.
Recommendation 2: Approximately 12-18 months, depending on extent of pilot.
Recommendation 3: Approximately 3-6 months, following completion of Recommendations 1 and 2, and pending their respective results.

These timelines are approximate estimates for preliminary pilot work. Full deployment across all of Enbridge Gas's assets would require longer as significant planning and thought would be required to scale up to full system coverage. The process would be iterative and would require considerable learning and adaptation, with different measurement technologies potentially being best suited for deployment on different parts of the system.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, attachment 1

Question(s):

These questions are for Highwood.

a) Please discuss the possibility of using tower, aerial, or satellite data in large urban centres not for leak detection, but to provide top-down overall emissions rates as one factor to help to assess the accuracy of bottom-up estimates.

b) Please discuss the cost of doing so.

Response:

The following responses were provided by Highwood Emissions Management:

a) Tower systems are discussed in the response at Exhibit I.ED-16 e). Aerial and satellite systems are discussed and modeled extensively throughout the Highwood Report.[1]

   For all three technologies (tower, aerial, satellite), natural gas distribution operators would need accurate, credible data on all other contributing emissions source categories, such as biogenic and customer emissions, to subtract these from the total measured top-down emissions to achieve a meaningful comparison, given that natural gas distribution is not the only methane source in urban environments.

b) Highwood is only aware of academic investigations and has not worked with any natural gas operators or technology vendors who have performed reconciliation using regional estimates. Therefore Highwood is unable to comment on the cost. However, we anticipate that while data collection would be expensive, the majority of the cost would be in analyzing the data as no standards or industry best practices exist for estimating and then disaggregating regional urban methane emissions.

[1] Exhibit D, Tab 1, Attachment 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit D, Tab 1, attachment 1

Question(s):

These questions are for Enbridge.

a) Highwood provides details for each of its recommendations from pages 95 and 101. Please provide a list of any elements or aspects of those recommendation details the Enbridge is not proposing to follow.

Response:

a) In relation to Recommendation 1 from Highwood to “develop company-specific emission factors based on source-level measurements for DO”,[1] Enbridge Gas has proposed to develop Company-specific emission factors on a subset of distribution assets,[2] pending OEB approvals.

In relation to Recommendation 2 from Highwood to “pilot mobile ground detection strategy for DO”,[3] Enbridge Gas has proposed to pilot a mobile ground technology on a subset of the distribution system,[4] pending OEB approvals.

In relation to Recommendation 3 from Highwood to “leverage data from Recommendations 1 and 2 to develop a measurement-informed inventory for DO”,[5] this is contingent on the outcomes of the measurement pilots and will be an ongoing process to incorporate measurement into the inventory.

In relation to Recommendation 4 from Highwood to “monitor advances in aerial and satellite performance”,[6] Enbridge Gas has proposed to “continue monitoring developments in aerial and satellite technologies to keep up with rapidly evolving industry and academic research”,[7] pending OEB approvals.

[1] Exhibit D, Tab 1, Attachment 1, p.95.
[2] Exhibit D, Tab 1, p.62.
[3] Exhibit D, Tab 1, Attachment 1, p.95.
[4] Exhibit D, Tab 1, p.63.
[5] Exhibit D, Tab 1, Attachment 1, p 95
[6] Exhibit D, Tab 1, Attachment 1, p.95.
[7] Exhibit D, Tab 1, p. 63.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (ED)

Interrogatory

Reference:

Exhibit H, Tab 1, Schedule 1,

Question(s):

a) Approximately when will the DCF+ test be completed and ready for use?

b) Please provide a detailed description of the latest iteration of the draft DCF+ test.

c) When considering IRPAs, will Enbridge offer interruptible rates discounts beyond the standard interruptible rate discounts? If yes, will the offer rates up to those corresponding to the cost of the avoided infrastructure?

d) Please provide a description of the three most promising projects for a potential IRPA.

e) What is Enbridge's best estimate of the year in which it will implement the next IRPA (aside from a pilot).

Response:

a) Enbridge Gas is in consultation with the IRP Technical Working Group (IRP TWG) on the DCF+ test and DCF+ Supplemental Guide as described at Exhibit H, Tab 1, Schedule 1, pages 20 – 21. Version 2 of the Draft DCF+ Supplemental Guide was provided to the IRP TWG August 19, 2024 for review. Enbridge Gas will use the methodology in the DCF+ Supplemental Guide in the IRP evaluation process, and the enhanced DCF+ test and accompanying DCF+ Supplemental Guide will be filed for OEB approval with its first non-pilot IRP Plan application.

b) Please see response at Exhibit I.ED-22 part a).

c) When evaluating Integrated Resource Planning Alternatives (IRPAs), Enbridge Gas will evaluate the use of a negotiated interruptible rate below posted rates to incent the service, recognizing that cost is only one aspect of customer choice. Negotiated rates, if applicable, would be determined by project-specific circumstances and IRP alternatives proposed.

d) Appendix C of the 2023 IRP Annual Report, filed as Exhibit H, Tab 1, Schedule 1, includes the updated status of the investments prioritized for IRP assessment and that have passed technical evaluation. As the economic evaluation has not yet been completed for investments that still remain within the 10-year Capital Plan, Enbridge Gas cannot identify the three most promising projects for a potential IRPA.

e) As the IRP evaluation process is still in progress, Enbridge Gas does not yet have an estimate for the year it will implement the next IRPA.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Page 1, Paragraph 2

Preamble:

"The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2017-0306/0307 OEB Decision and Order, dated August 30, 2018, at pages 28 and 29, and within theEB-2017-0306 pre-filed evidence at Exhibit B, Tab 1, pages 42 and 43:

- if in any calendar year during the deferred rebasing term, Enbridge Gas's actual utility ROE is more than 150 basis points above the OEB-approved ROE for that year (updated annually by the OEB), then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge Gas and its ratepayers;

Question(s):

a) Since the August 30, 2018, OEB, decision, how many applications for disposition of earnings sharing and deferral and variance accounts has Enbridge Gas filed?

b) When was the last time that Enbridge Gas had adequate earnings to share with ratepayers?

c) Should the OEB be concerned about inadequate earnings of Enbridge Gas?

Response:

a) Since the August 30, 2018 OEB Decision in the MAADs application[1], Enbridge Gas has filed 6 Earnings Sharing and Deferral Disposition applications. In 2019, following amalgamation on January 1, 2019, Enbridge Gas filed a 2018 Earnings Sharing and Deferral Disposition application[2]. While a single application, it separately presented

[1] EB-2017-0306/0307.
[2] EB-2019-0105.

the 2018 pre-amalgamation independent results and deferral accounts for both EGD and Union and reflected earnings sharing parameters that were in place for each respective entity. Subsequently, in each of 2020 – 2024, Enbridge Gas has filed Earnings Sharing and Deferral Disposition applications reflecting Enbridge Gas amalgamated results for each of 2019 – 2023 and the earning sharing parameters approved as part of the EB-2017-0306/0307 OEB Decision. These applications included rate zone specific deferral accounts that continued on over the deferred rebasing period, as well as, Enbridge Gas accounts that were approved as part of EB-2017-0306/0307, or through other proceedings that occurred post amalgamation.

b) Enbridge Gas was not in an earnings sharing position for the deferred rebasing period of January 1, 2019 through December 31, 2023. Prior to this, the last time that either EGD or Union had adequate earnings to share with ratepayers was for 2018, when EGD shared within the parameters of its Custom IR framework, different from Enbridge Gas as of 2019.

c) No, the OEB should not be concerned about the earnings of Enbridge Gas. Achieved earnings of Enbridge Gas in each year during the deferred rebasing period were within the OEB approved parameters of allowed ROE for earnings sharing and off-ramp considerations. As noted in the response at Exhibit I.SEC-1, the utility results of Enbridge Gas for 2023 were significantly impacted by one time write-offs (and warmer weather) as a result of OEB decisions that are not expected to recur on a regular basis.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 2, Page 1, EGI Utility Income (2023 Actual), Line 8, Operation and Maintenance and Note (v)

Question(s):

a) Are any costs of Enbridge Sustain included in the Operation and Maintenance $1,303.2 million amount in Col.1? Please explain your answer.

b) Are any costs of Enbridge Sustain included in the ($170.3 million) Adjustments in Col.3? Please explain your answer.

Response:

a) Yes, Enbridge Sustain O&M of $6.4 million is included in the $1,303.2 million in line 8, column 1. During 2023, Enbridge Sustain was an unregulated line of business carried out by Enbridge Gas. As such, its results are included in the Enbridge Gas corporate results which serve as the starting point for the determination of utility results and any potential earnings sharing. However, as an unregulated line of business, Enbridge Sustain results are removed/eliminated as part of the removal/elimination of Unregulated Operations results in line 8, column 2.

b) No, there are no Enbridge Sustain costs included in the $170.3 million adjustments in line 8, column 3. The elimination of the $6.4 million of Enbridge Sustain costs from Utility results is included in line 8, column 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 6, Page 1, Reconciliation of Audited Enbridge Gas Inc. Income (Per Financial Statements) to Corporate Income for Utility Income Determination Purposes, (2003 Actual), Cols.1 and 2, Line 6

Question(s):

a) In Col.1, Audited Income, Line 6, what is Other Income of $47.5 million?

b) Please break down $47.5 million Other Income into revenues and expenses.

c) In Col.2, Corporate Income, Line 6, what is Other Income of $11.1 million?

d) Please break down $11.1 million into revenues and expenses.

e) How does the $47.5 million in Col.1 relate to the $11.1 million?

f) Are 2023 Enbridge Sustain revenues or costs included in any line in either Col. 1 or Col. 2? Please explain your answer.

Response:

a) and b)

See Table 1 for the makeup of the $47.5 million as well as the breakdown into revenues and expenses:

Table 1
Other Income – Audited Income

Line No.	Particulars	Amount ($ millions)
1	Pension related other revenue[1]	37.0
2	Gain on sale of assets	5.5
3	Foreign exchange gains and other income	3.0
4	Interest income	2.6
5	Subtotal – other income/revenues	48.1
6	Other miscellaneous O&M expense	(0.6)
7	Other Income – Audited	47.5

c) - d)

See Table 2 for the makeup of the $11.1 million as well as the breakdown into revenues and expenses:

Table 2
Other Income – Corporate Income

Line No.	Particulars	Amount ($ millions)
1	Gain on sale of assets	5.5
2	Foreign exchange gains and other income	3.0
3	Interest income	2.6
4	Subtotal – other income/revenues	11.1
5	Other miscellaneous O&M expense	0.0
6	Other Income – Corporate	11.1

e) The $47.5 million of other income as per the audited financial statements of Enbridge Gas Inc. are adjusted for presentation purposes whereby the pension related other revenue and other miscellaneous O&M expense in Table 1 above are reclassified to O&M in the Utility Income Schedule. The $36.4 million reclassification is offset in line 9 of Exhibit B, Tab 1, Schedule 6.

f) Enbridge Sustain revenues in 2023 were less than $5,000 and were included in line 2 of Col 1 and line 5 of Col 2 of Exhibit B, Tab 1, Schedule 6. From there, these revenues are segregated as part of Unregulated Operations as noted in Exhibit B, Tab 1, Schedule 2, line 4, Col 2 and therefore not included in Utility operating revenue.

[1] Includes expected return on pension assets, amortization of actuarial gains/losses and past service costs, pension interest cost.

Enbridge Sustain costs are almost entirely included in line 9 of both Col 1 and Col 2 in Exhibit B, Tab 1, Schedule 6 as they form part of the total O&M of Enbridge Gas. There are immaterial amounts less than $20,000 in line 10 of both Col 1 and Col 2 in Exhibit B, Tab 1, Schedule 6 representing depreciation of Sustain property, plant and equipment in 2023. From there, these costs are segregated as part of Unregulated Operations as noted in Exhibit B, Tab 1, Schedule 2, line 8 and 9, Col 2 and therefore not included in Utility O&M.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 4, page 1, EGI Utility Other Revenue and Other Income, 2023 Actual, Lines 3 and 9

Question(s):

a) What is Other Billing Revenue and why has it increased from $9.7 million in 2022 to $11.1 million in 2023?

b) What is Other Operating Revenue and why has it increased from $2.6 million in 2022 to $3.1 million in 2023?

Response:

a) Other billing revenue is comprised of the following charges: non-sufficient funds (NSF), construction heat activation, safety inspection, seasonal meter unlocks, meter dispute tests, service line alterations, damage cost recovery charges and certain customer charges. The increase from 2022 to 2023 is primarily related to $2 million in damage cost recovery offset by ($0.6) million of service line alterations.

b) Other operating revenue is comprised of the following components: stale-dated cheques, third-party maintenance revenue, affiliate lease revenue and miscellaneous immaterial one-time adjustments to revenue. The increase from 2022 to 2023 is primarily attributable to unclaimed customer cheques.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Page 2, Table 1, Line 25, Table 1, Utility O&M, 2022-2023 Actuals, and Page 3, paragraph 5.

Preamble:

"Miscellaneous Expense (Line 16) increased $283.4 million over the prior year primarily due to impairment charges related to the OEB Settlement and Phase 1 rebasing decisions driven by the pension balance write-off ($156.1 million), write-off of net capital integration costs ($84.3 million), and GTA/WAMS capital write-offs ($41.0 million). The pension write-off of $156.1 million is considered non-utility cost and is eliminated on Line 25."

Question(s):

a) Please explain the reason for the Pension Impairment Elimination of $156.1 million in 2023.

b) Please provide the back up calculation that supports the $156.1 million amount.

c) Why is the pension write-off considered non-utility?

Response:

a) In its Decision and Order dated December 21, 2023[1], the OEB denied Enbridge Gas' proposed recovery of the Pension & OPEB expenses as recorded in the APCDA for the pre-2017 Union unamortized actuarial gains/losses. As the Decision and Order was received prior to the end of 2023, Enbridge Gas was required under US GAAP[2] to recognize an impairment loss at the time of the Decision and Order and therefore, the impairment loss was recognized as part of the 2023 Enbridge Gas Consolidated Statements of Earnings.

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[1] EB-2022-0200, Decision and Order, December 21, 2023, p.106.
[2] ASC 980-340-40-1: If at any time an entity's incurred cost no longer meets the criteria for capitalization of an incurred cost, that cost shall be charged to earnings.

b) The $156.1 million represents the actual unamortized balance on Enbridge Gas' balance sheet at the time of the Decision and Order. The calculation that supports the $156.1 million was provided by Mercer, please see Attachment 1 and the referenced amount located on pages 10 and 12 of the attachment.

c) In its Decision and Order[3], the OEB commented as follows:

> The OEB finds that Enbridge Gas's $156 million entry in the APCDA was not consistent with the intent of the regulatory account. The OEB finds that the $156 million was not the result of an accounting policy change after January 1, 2019. The APCDA was not a subsequent opportunity for Enbridge Gas to recharacterize $156 million recorded as goodwill in 2018 as a regulatory asset in 2019. Further, goodwill should not have been included in a regulatory asset since goodwill is not recoverable in rates.

As such, as an amount that was deemed to be unrecoverable from utility ratepayers Enbridge Gas determined that it would not be appropriate to include in utility results and therefore removed the amount as a utility adjustment. The result is that the amount written off does not impact 2023 utility results or achieved Return on Equity.

[3] EB-2022-0200, Decision and Order, December 21, 2023, p.107.

Enbridge Gas Inc. - Projected US GAAP Accrual Costs (2022 to 2024)

Company's Share US GAAP ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
2022						
DB Current service cost (employer)	52,553	6,245	208	-	-	-
Interest cost	6,479	29,493	16,708	3,877	3,406	1,515
Expected return on plan assets	(13,139)	(77,801)	(37,320)	(8,706)	(8,235)	(3,643)
Amortization of past service costs	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	-	7,775	-	-	-	-
Total DB Net Periodic Benefit Cost	45,893	(34,288)	(20,404)	(4,829)	(4,829)	(2,128)
DC Current Service Cost	2,547	69	294	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**48,440**	**(34,219)**	**(20,110)**	**(4,829)**	**(4,829)**	**(2,128)**
2023						
DB Current service cost (employer)	31,334	3,532	138	-	-	-
Interest cost	10,146	43,911	22,884	6,108	5,362	2,400
Expected return on plan assets	(14,450)	(71,522)	(33,799)	(7,186)	(6,828)	(3,009)
Amortization of past service costs	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	-	51	-	-	-	-
Total DB Net Periodic Benefit Cost	27,030	(24,028)	(10,777)	(1,078)	(1,466)	(609)
DC Current Service Cost	3,409	72	266	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**30,439**	**(23,956)**	**(10,511)**	**(1,078)**	**(1,466)**	**(609)**
2024						
DB Current service cost (employer)	30,879	3,463	129	-	-	-
Interest cost	12,531	43,518	22,719	5,869	5,144	2,300
Expected return on plan assets	(16,028)	(72,618)	(34,294)	(7,013)	(6,693)	(2,944)
Amortization of past service costs	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	-	-	-	-	-	-
Total DB Net Periodic Benefit Cost	27,382	(25,637)	(11,446)	(1,144)	(1,549)	(644)
DC Current Service Cost	4,149	74	246	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**31,531**	**(25,563)**	**(11,200)**	**(1,144)**	**(1,549)**	**(644)**

Key Assumptions[1]	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
Effective discount rate on benefit obligations	5.27%	5.27%	5.27%	5.26%	5.26%	5.26%
Effective rate for interest on benefit obligations	5.25%	5.21%	5.22%	5.20%	5.19%	5.19%
Effective discount rate for service cost	5.26%	5.25%	5.26%	N/A	N/A	N/A
Effective rate for interest on service cost	5.21%	5.23%	5.26%	N/A	N/A	N/A
Expected return on assets	7.10%	6.70%	6.60%	5.00%	5.00%	5.00%
Net expected return on assets	7.10%	6.70%	6.60%	5.00%	5.00%	5.00%
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age
Average wage index	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year
Mortality table	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B

[1] Effective discount rates and interest rates disclosed are based on market conditions as at December 31, 2022

Mercer

Enbridge Gas Inc. - Projected US GAAP Accrual Costs (2022 to 202

Company's Share US GAAP ('000s)	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
2022									
DB Current service cost (employer)	-	-	-	-	1,212	-	1,833	60,218	62,051
Interest cost	207	188	311	56	631	1,440	4,252	64,311	68,563
Expected return on plan assets	(491)	(500)	(417)	(228)	(932)	-	-	(151,412)	(151,412)
Amortization of past service costs	-	-	-	-	-	-	(27)	-	(27)
Amortization of net actuarial loss (gain)	-	-	204	-	12	38	(922)	8,029	7,107
Total DB Net Periodic Benefit Cost	(284)	(312)	98	(172)	923	1,478	5,136	(18,854)	(13,718)
DC Current Service Cost	-	-	-	-	-	-	-	2,910	2,910
Total (DB & DC) Net Periodic Benefit Cost	**(284)**	**(312)**	**98**	**(172)**	**923**	**1,478**	**5,136**	**(15,944)**	**(10,808)**
2023									
DB Current service cost (employer)	-	-	-	-	885	-	1,144	35,889	37,033
Interest cost	338	308	574	131	937	2,151	6,057	95,250	101,307
Expected return on plan assets	(429)	(440)	(376)	(211)	(737)	-	-	(138,987)	(138,987)
Amortization of past service costs	-	-	-	-	-	-	(27)	-	(27)
Amortization of net actuarial loss (gain)	-	-	169	-	-	-	(3,731)	220	(3,511)
Total DB Net Periodic Benefit Cost	(91)	(132)	367	(80)	1,085	2,151	3,443	(7,628)	(4,185)
DC Current Service Cost	-	-	-	-	-	-	-	3,747	3,747
Total (DB & DC) Net Periodic Benefit Cost	**(91)**	**(132)**	**367**	**(80)**	**1,085**	**2,151**	**3,443**	**(3,881)**	**(438)**
2024									
DB Current service cost (employer)	-	-	-	-	907	-	1,144	35,378	36,522
Interest cost	340	310	573	126	989	2,105	6,063	96,524	102,587
Expected return on plan assets	(427)	(440)	(372)	(208)	(809)	-	-	(141,846)	(141,846)
Amortization of past service costs	-	-	-	-	-	-	(27)	-	(27)
Amortization of net actuarial loss (gain)	-	-	138	-	-	-	(3,476)	138	(3,338)
Total DB Net Periodic Benefit Cost	(87)	(130)	339	(82)	1,087	2,105	3,704	(9,806)	(6,102)
DC Current Service Cost	-	-	-	-	-	-	-	4,469	4,469
Total (DB & DC) Net Periodic Benefit Cost	**(87)**	**(130)**	**339**	**(82)**	**1,087**	**2,105**	**3,704**	**(5,337)**	**(1,633)**

Key Assumptions[1]	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB (EGD/UG)
Effective discount rate on benefit obligations	5.26%	5.26%	5.25%	5.16%	5.28%	5.26%	5.27%/5.27%
Effective rate for interest on benefit obligations	5.20%	5.20%	5.19%	5.14%	5.23%	5.20%	5.23%/5.22%
Effective discount rate for service cost	N/A	N/A	N/A	N/A	5.28%	N/A	5.27%/5.27%
Effective rate for interest on service cost	N/A	N/A	N/A	N/A	5.23%	N/A	5.27%/5.27%
Expected return on assets	5.00%	5.00%	3.00%	3.00%	4.20%	N/A	N/A
Net expected return on assets	5.00%	5.00%	3.00%	3.00%	4.20%	N/A	N/A
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	N/A	N/A	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	N/A
Average wage index	2.5% per year	2.5% per year	N/A	N/A	2.5% per year	2.5% per year	N/A
Mortality table	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B

[1] Effective discount rates and interest rates disclosed are based on market cor

Enbridge Gas Inc. - Projected Cash Contributions (2022 to 2024)

Company's Share Projected Contributions ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
2022						
DB Current Service Cost	25,045	-	33	-	-	-
DC Current Service Cost	2,547	69	294	-	-	-
Going Concern Special Payments	-	-	-	-	-	-
Solvency Special Payments	9,124	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	-
Total	**36,716**	**69**	**327**	**-**	**-**	**-**
2023						
DB Current Service Cost	-	-	-	-	-	-
DC Current Service Cost	3,409	72	266	-	-	-
Going Concern Special Payments	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	-
Total	**3,409**	**72**	**266**	**-**	**-**	**-**
2024						
DB Current Service Cost	-	-	-	-	-	-
DC Current Service Cost	4,149	74	246	-	-	-
Going Concern Special Payments	-	-	-	-	-	-
Solvency Special Payments	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	-
Total	**4,149**	**74**	**246**	**-**	**-**	**-**

Key Assumptions	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
Going concern discount rate	7.05%	6.60%	6.55%	5.45%	5.45%	5.45%
Provision for adverse deviation	9.70%	11.00%	11.00%	9.00%	9.00%	9.00%
Going concern mortality	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B
Commuted value discount rate	4.50% for 10 years; 5.00% thereafter	N/A	N/A	N/A	N/A	N/A
Annuity proxy discount rate	4.48%	N/A	N/A	N/A	N/A	N/A
Solvency mortality	100% CPM Combined, with improvements based on scale CPM-B	N/A	N/A	N/A	N/A	N/A
Net expected return on assets	7.10%	6.70%	6.60%	5.00%	5.00%	5.00%
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age
Average wage index	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year

Enbridge Gas Inc. - Projected Cash Contributions (2022 to 2024)

Company's Share Projected Contributions ('000s)	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
2022									
DB Current Service Cost	-	-	-	-	-	-	-	25,078	25,078
DC Current Service Cost	-	-	-	-	-	-	-	2,910	2,910
Going Concern Special Payments	-	-	-	-	67	-	-	67	67
Solvency Special Payments	-	-	-	-	-	-	-	9,124	9,124
Direct Benefit Payments	-	-	-	-	-	3,004	4,785	3,004	7,789
Total	**-**	**-**	**-**	**-**	**67**	**3,004**	**4,785**	**40,183**	**44,968**
2023									
DB Current Service Cost	-	-	-	-	1,042	-	-	1,042	1,042
DC Current Service Cost	-	-	-	-	-	-	-	3,747	3,747
Going Concern Special Payments	-	-	317	-	848	-	-	1,165	1,165
Solvency Special Payments	-	-	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	3,023	7,090	3,023	10,113
Total	**-**	**-**	**317**	**-**	**1,890**	**3,023**	**7,090**	**8,977**	**16,067**
2024									
DB Current Service Cost	-	-	-	-	1,068	-	-	1,068	1,068
DC Current Service Cost	-	-	-	-	-	-	-	4,469	4,469
Going Concern Special Payments	-	-	317	-	833	-	-	1,150	1,150
Solvency Special Payments	-	-	-	-	-	-	-	-	-
Direct Benefit Payments	-	-	-	-	-	3,032	7,153	3,032	10,185
Total	**-**	**-**	**317**	**-**	**1,901**	**3,032**	**7,153**	**9,719**	**16,872**

Key Assumptions	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
Going concern discount rate	5.45%	5.45%	3.00%	3.00%	4.20%	N/A	N/A		
Provision for adverse deviation	9.00%	9.00%	N/A	N/A	N/A	N/A	N/A		
Going concern mortality	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	N/A	N/A		
Commuted value discount rate	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Annuity proxy discount rate	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Solvency mortality	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Net expected return on assets	5.00%	5.00%	3.00%	3.00%	4.80%	N/A	N/A		
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	N/A	N/A	Ranges from 2.50% to 5.00% based on age	N/A	N/A		
Average wage index	2.5% per year	2.5% per year	N/A	N/A	2.5% per year	N/A	N/A		

Enbridge Gas Inc. - Projected US GAAP Balance Sheet (December 31, 2021 to December 31, 2023)

Company's Share US GAAP ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
December 31, 2021						
Fair value of plan assets	161,408	1,187,366	578,449	179,522	169,633	75,041
Benefit obligation	211,785	1,097,187	605,735	156,840	139,053	61,785
Funded status (plan assets less benefit obligations)	**(50,377)**	**90,179**	**(27,286)**	**22,682**	**30,580**	**13,256**
Prior service credit (cost)	-	-	-	-	-	-
Net gain (loss)	13,618	(214,077)	(55,476)	(3,051)	(1,276)	(2,320)
Accumulated other comprehensive income (loss)	13,618	(214,077)	(55,476)	(3,051)	(1,276)	(2,320)
Accumulated contributions in excess of net periodic benefit cost	(63,995)	304,256	28,191	25,733	31,856	15,576
Net amount [surplus (deficit)] recognized in statement of financial position	(50,377)	90,179	(27,286)	22,682	30,580	13,256
December 31, 2022						
Fair value of plan assets	199,321	1,094,723	525,200	149,077	141,353	62,359
Benefit obligation	195,591	869,368	451,348	122,933	108,047	48,401
Funded status (plan assets less benefit obligations)	**3,731**	**225,355**	**73,852**	**26,144**	**33,306**	**13,958**
Prior service credit (cost)	-	-	-	-	-	-
Net gain (loss)	79,451	(113,188)	25,224	(4,418)	(3,379)	(3,745)
Accumulated other comprehensive income (loss)	79,451	(113,188)	25,224	(4,418)	(3,379)	(3,745)
Accumulated contributions in excess of net periodic benefit cost	(75,720)	338,543	48,628	30,562	36,685	17,703
Net amount [surplus (deficit)] recognized in statement of financial position	3,731	225,355	73,852	26,144	33,306	13,958
December 31, 2023						
Fair value of plan assets	222,163	1,111,783	532,806	145,543	138,576	61,019
Benefit obligation	241,647	862,702	448,368	118,281	103,821	46,479
Funded status (plan assets less benefit obligations)	**(19,483)**	**249,081**	**84,438**	**27,262**	**34,755**	**14,540**
Prior service credit (cost)	-	-	-	-	-	-
Net gain (loss)	83,266	(113,491)	25,032	(4,379)	(3,396)	(3,772)
Accumulated other comprehensive income (loss)	83,266	(113,491)	25,032	(4,379)	(3,396)	(3,772)
Accumulated contributions in excess of net periodic benefit cost	(102,751)	362,572	59,406	31,640	38,151	18,313
Net amount [surplus (deficit)] recognized in statement of financial position	(19,483)	249,081	84,438	27,262	34,755	14,540
Net gain (loss) on local books basis at December 31, 2023	83,266	(113,491)	(48,136)	(32,533)	(32,603)	(16,712)
Local books AOCI (loss) in excess of corporate books	**-**	**-**	**(73,168)**	**(28,154)**	**(29,207)**	**(12,940)**

Key Assumptions[1]	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
Effective discount rate on benefit obligations	5.27%	5.27%	5.27%	5.26%	5.26%	5.26%
Effective rate for interest on benefit obligations	5.25%	5.21%	5.22%	5.20%	5.19%	5.19%
Effective discount rate for service cost	5.26%	5.25%	5.26%	N/A	N/A	N/A
Effective rate for interest on service cost	5.21%	5.23%	5.26%	N/A	N/A	N/A
Expected return on assets	7.10%	6.70%	6.60%	5.00%	5.00%	5.00%
Net expected return on assets	7.10%	6.70%	6.60%	5.00%	5.00%	5.00%
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age
Average wage index	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year
Mortality table	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B

[1] Effective discount rates and interest rates disclosed are based on market conditions as at December 31, 2022

Enbridge Gas Inc. - Projected US GAAP Balance Sheet (December 3

Company's Share US GAAP ('000s)	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
December 31, 2021									
Fair value of plan assets	10,492	10,678	14,927	8,075	19,766	-	-	2,415,357	2,415,357
Benefit obligation	9,023	8,371	14,815	3,438	22,371	54,968	156,706	2,385,371	2,542,077
Funded status (plan assets less benefit obligations)	**1,468**	**2,308**	**113**	**4,638**	**(2,605)**	**(54,968)**	**(156,706)**	**29,988**	**(126,718)**
Prior service credit (cost)	-	-	-	-	-	-	(275)	-	(275)
Net gain (loss)	(226)	(440)	(4,197)	22	(389)	(11,867)	12,038	(279,679)	(267,641)
Accumulated other comprehensive income (loss)	(226)	(440)	(4,197)	22	(389)	(11,867)	11,763	(279,679)	(267,916)
Accumulated contributions in excess of net periodic benefit cost	1,694	2,748	4,309	4,616	(2,215)	(43,101)	(168,469)	309,668	141,199
Net amount [surplus (deficit)] recognized in statement of financial position	1,468	2,308	113	4,638	(2,605)	(54,968)	(156,706)	29,988	(126,718)
December 31, 2022									
Fair value of plan assets	8,843	9,043	13,073	7,241	17,028	-	-	2,227,261	2,227,261
Benefit obligation	7,176	6,557	12,406	2,963	18,319	42,775	119,442	1,885,884	2,005,326
Funded status (plan assets less benefit obligations)	**1,668**	**2,485**	**668**	**4,278**	**(1,291)**	**(42,775)**	**(119,442)**	**341,379**	**221,937**
Prior service credit (cost)	-	-	-	-	-	-	(302)	-	(302)
Net gain (loss)	(311)	(574)	(3,543)	(510)	1,848	(1,201)	49,680	(24,346)	25,334
Accumulated other comprehensive income (loss)	(311)	(574)	(3,543)	(510)	1,848	(1,201)	49,378	(24,346)	25,032
Accumulated contributions in excess of net periodic benefit cost	1,979	3,060	4,211	4,788	(3,139)	(41,575)	(168,820)	365,725	196,905
Net amount [surplus (deficit)] recognized in statement of financial position	1,668	2,485	668	4,278	(1,291)	(42,775)	(119,442)	341,379	221,937
December 31, 2023									
Fair value of plan assets	8,801	9,043	12,802	7,135	18,789	-	-	2,268,460	2,268,460
Benefit obligation	6,806	6,213	11,608	2,650	19,369	41,907	119,604	1,909,851	2,029,455
Funded status (plan assets less benefit obligations)	**1,995**	**2,830**	**1,194**	**4,485**	**(580)**	**(41,907)**	**(119,604)**	**358,610**	**239,006**
Prior service credit (cost)	-	-	-	-	-	-	(328)	-	(328)
Net gain (loss)	(75)	(361)	(2,968)	(383)	1,837	(1,204)	45,897	(19,894)	26,003
Accumulated other comprehensive income (loss)	(75)	(361)	(2,968)	(383)	1,837	(1,204)	45,569	(19,894)	25,675
Accumulated contributions in excess of net periodic benefit cost	2,070	3,191	4,161	4,868	(2,417)	(40,702)	(165,173)	378,502	213,329
Net amount [surplus (deficit)] recognized in statement of financial position	1,995	2,830	1,194	4,485	(580)	(41,907)	(119,604)	358,610	239,006
Net gain (loss) on local books basis at December 31, 2023	(2,094)	(2,262)	(2,968)	(383)	1,837	(13,948)	49,893	(180,027)	(130,134)
Local books AOCI (loss) in excess of corporate books	**(2,019)**	**(1,901)**	**-**	**-**	**-**	**(12,744)**	**3,996**	**(160,133)**	**(156,137)**

Key Assumptions[1]	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB (EGD/UG)	Total Pension	Grand Total
Effective discount rate on benefit obligations	5.26%	5.26%	5.25%	5.16%	5.28%	5.26%	5.27%/5.27%		
Effective rate for interest on benefit obligations	5.20%	5.20%	5.19%	5.14%	5.23%	5.20%	5.23%/5.22%		
Effective discount rate for service cost	N/A	N/A	N/A	N/A	5.28%	N/A	5.27%/5.27%		
Effective rate for interest on service cost	N/A	N/A	N/A	N/A	5.23%	N/A	5.27%/5.27%		
Expected return on assets	5.00%	5.00%	3.00%	3.00%	4.20%	N/A	N/A		
Net expected return on assets	5.00%	5.00%	3.00%	3.00%	4.20%	N/A	N/A		
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	N/A		
Average wage index	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year	N/A		
Mortality table	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B		

[1] Effective discount rates and interest rates disclosed are based on market cor

Enbridge Gas Inc. - Projected US GAAP Accrual Costs (2022 to 2024)

Company's Share US GAAP ('000s) - Local Books	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
2022						
DB Current service cost (employer)	52,553	6,245	208	-	-	-
Interest cost	6,479	29,493	16,708	3,877	3,406	1,515
Expected return on plan assets	(13,139)	(77,801)	(37,320)	(8,706)	(8,235)	(3,643)
Amortization of past service costs	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	-	7,775	4,854	1,155	1,162	590
Total DB Net Periodic Benefit Cost	45,893	(34,288)	(15,550)	(3,674)	(3,667)	(1,538)
DC Current Service Cost	2,547	69	294	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**48,440**	**(34,219)**	**(15,256)**	**(3,674)**	**(3,667)**	**(1,538)**
2023						
DB Current service cost (employer)	31,334	3,532	138	-	-	-
Interest cost	10,146	43,911	22,884	6,108	5,362	2,400
Expected return on plan assets	(14,450)	(71,522)	(33,799)	(7,186)	(6,828)	(3,009)
Amortization of past service costs	-	-	-	-	-	-
Amortization of net actuarial loss (gain)	-	51	-	1,421	1,475	753
Total DB Net Periodic Benefit Cost	27,030	(24,028)	(10,777)	343	9	144
DC Current Service Cost	3,409	72	266	-	-	-
Total (DB & DC) Net Periodic Benefit Cost	**30,439**	**(23,956)**	**(10,511)**	**343**	**9**	**144**

Key Assumptions[1]	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
Effective discount rate on benefit obligations	5.27%	5.27%	5.27%	5.26%	5.26%	5.26%
Effective rate for interest on benefit obligations	5.25%	5.21%	5.22%	5.20%	5.19%	5.19%
Effective discount rate for service cost	5.26%	5.25%	5.26%	N/A	N/A	N/A
Effective rate for interest on service cost	5.21%	5.23%	5.26%	N/A	N/A	N/A
Expected return on assets	7.10%	6.70%	6.60%	5.00%	5.00%	5.00%
Net expected return on assets	7.10%	6.70%	6.60%	5.00%	5.00%	5.00%
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age
Average wage index	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year
Mortality table	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B

[1] Effective discount rates and interest rates disclosed are based on market conditions as at December 31, 2022

Enbridge Gas Inc. - Projected US GAAP Accrual Costs (2022 to 2024)

Company's Share US GAAP ('000s) - Local Books	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
2022									
DB Current service cost (employer)	-	-	-	-	1,212	-	1,833	60,218	62,051
Interest cost	207	188	311	56	631	1,440	4,252	64,311	68,563
Expected return on plan assets	(491)	(500)	(417)	(228)	(932)	-	-	(151,412)	(151,412)
Amortization of past service costs	-	-	-	-	-	-	(27)	-	(27)
Amortization of net actuarial loss (gain)	78	76	204	-	12	1,384	(1,153)	17,290	16,137
Total DB Net Periodic Benefit Cost	(206)	(236)	98	(172)	923	2,824	4,905	(9,593)	(4,688)
DC Current Service Cost	-	-	-	-	-	-	-	2,910	2,910
Total (DB & DC) Net Periodic Benefit Cost	**(206)**	**(236)**	**98**	**(172)**	**923**	**2,824**	**4,905**	**(6,683)**	**(1,778)**
2023									
DB Current service cost (employer)	-	-	-	-	885	-	1,144	35,889	37,033
Interest cost	338	308	574	131	937	2,151	6,057	95,250	101,307
Expected return on plan assets	(429)	(440)	(376)	(211)	(737)	-	-	(138,987)	(138,987)
Amortization of past service costs	-	-	-	-	-	-	(27)	-	(27)
Amortization of net actuarial loss (gain)	92	88	169	-	-	651	(3,944)	4,700	756
Total DB Net Periodic Benefit Cost	1	(44)	367	(80)	1,085	2,802	3,230	(3,148)	82
DC Current Service Cost	-	-	-	-	-	-	-	3,747	3,747
Total (DB & DC) Net Periodic Benefit Cost	**1**	**(44)**	**367**	**(80)**	**1,085**	**2,802**	**3,230**	**599**	**3,829**

Key Assumptions[1]	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB (EGD/UG)
Effective discount rate on benefit obligations	5.26%	5.26%	5.25%	5.16%	5.28%	5.26%	5.27%/5.27%
Effective rate for interest on benefit obligations	5.20%	5.20%	5.19%	5.14%	5.23%	5.20%	5.23%/5.22%
Effective discount rate for service cost	N/A	N/A	N/A	N/A	5.28%	N/A	5.27%/5.27%
Effective rate for interest on service cost	N/A	N/A	N/A	N/A	5.23%	N/A	5.27%/5.27%
Expected return on assets	5.00%	5.00%	3.00%	3.00%	4.20%	N/A	N/A
Net expected return on assets	5.00%	5.00%	3.00%	3.00%	4.20%	N/A	N/A
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	N/A	N/A	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	N/A
Average wage index	2.5% per year	2.5% per year	N/A	N/A	2.5% per year	2.5% per year	N/A
Mortality table	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B

[1] Effective discount rates and interest rates disclosed are based on market conditior

Enbridge Gas Inc. - Projected US GAAP Balance Sheet (December 31, 2021 to December 31, 2023)

Company's Share US GAAP ('000s) - Local Books	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
December 31, 2021						
Fair value of plan assets	161,408	1,187,366	578,449	179,522	169,633	75,041
Benefit obligation	211,785	1,097,187	605,735	156,840	139,053	61,785
Funded status (plan assets less benefit obligations)	**(50,377)**	**90,179**	**(27,286)**	**22,682**	**30,580**	**13,256**
Prior service credit (cost)	-	-	-	-	-	-
Net gain (loss)	13,618	(214,077)	(133,498)	(33,782)	(33,120)	(16,603)
Accumulated other comprehensive income (loss)	13,618	(214,077)	(133,498)	(33,782)	(33,120)	(16,603)
Accumulated contributions in excess of net periodic benefit cost	(63,995)	304,256	106,212	56,464	63,700	29,859
Net amount [surplus (deficit)] recognized in statement of financial position	(50,377)	90,179	(27,286)	22,682	30,580	13,256
December 31, 2022						
Fair value of plan assets	199,321	1,094,723	525,200	149,077	141,353	62,359
Benefit obligation	195,591	869,368	451,348	122,933	108,047	48,401
Funded status (plan assets less benefit obligations)	**3,731**	**225,355**	**73,852**	**26,144**	**33,306**	**13,958**
Prior service credit (cost)	-	-	-	-	-	-
Net gain (loss)	79,451	(113,188)	(47,944)	(33,994)	(34,061)	(17,438)
Accumulated other comprehensive income (loss)	79,451	(113,188)	(47,944)	(33,994)	(34,061)	(17,438)
Accumulated contributions in excess of net periodic benefit cost	(75,720)	338,543	121,796	60,138	67,367	31,396
Net amount [surplus (deficit)] recognized in statement of financial position	3,731	225,355	73,852	26,144	33,306	13,958
December 31, 2023						
Fair value of plan assets	222,163	1,111,783	532,806	145,543	138,576	61,019
Benefit obligation	241,647	862,702	448,368	118,281	103,821	46,479
Funded status (plan assets less benefit obligations)	**(19,483)**	**249,081**	**84,438**	**27,262**	**34,755**	**14,540**
Prior service credit (cost)	-	-	-	-	-	-
Net gain (loss)	83,266	(113,491)	(48,136)	(32,533)	(32,603)	(16,712)
Accumulated other comprehensive income (loss)	83,266	(113,491)	(48,136)	(32,533)	(32,603)	(16,712)
Accumulated contributions in excess of net periodic benefit cost	(102,749)	362,572	132,574	59,795	67,358	31,252
Net amount [surplus (deficit)] recognized in statement of financial position	(19,483)	249,081	84,438	27,262	34,755	14,540
Net gain (loss) on corporate books basis at December 31, 2023	83,266	(113,491)	25,032	(4,379)	(3,396)	(3,772)
Local books AOCI (loss) in excess of corporate books	**-**	**-**	**(73,168)**	**(28,154)**	**(29,207)**	**(12,940)**

Key Assumptions[1]	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
Effective discount rate on benefit obligations	5.27%	5.27%	5.27%	5.26%	5.26%	5.26%
Effective rate for interest on benefit obligations	5.25%	5.21%	5.22%	5.20%	5.19%	5.19%
Effective discount rate for service cost	5.26%	5.25%	5.26%	N/A	N/A	N/A
Effective rate for interest on service cost	5.21%	5.23%	5.26%	N/A	N/A	N/A
Expected return on assets	7.10%	6.70%	6.60%	5.00%	5.00%	5.00%
Net expected return on assets	7.10%	6.70%	6.60%	5.00%	5.00%	5.00%
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age
Average wage index	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year
Mortality table	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B

[1] Effective discount rates and interest rates disclosed are based on market conditions as at December 31, 2022

Enbridge Gas Inc. - Projected US GAAP Balance Sheet (December 31,

Company's Share US GAAP ('000s) - Local Books	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
December 31, 2021									
Fair value of plan assets	10,492	10,678	14,927	8,075	19,766	-	-	2,415,357	2,415,357
Benefit obligation	9,023	8,371	14,815	3,438	22,371	54,968	156,706	2,385,371	2,542,077
Funded status (plan assets less benefit obligations)	**1,468**	**2,308**	**113**	**4,638**	**(2,605)**	**(54,968)**	**(156,706)**	**29,988**	**(126,718)**
Prior service credit (cost)	-	-	-	-	-	-	(275)	-	(275)
Net gain (loss)	(2,415)	(2,505)	(4,197)	22	(389)	(26,608)	16,478	(453,554)	(437,076)
Accumulated other comprehensive income (loss)	(2,415)	(2,505)	(4,197)	22	(389)	(26,608)	16,203	(453,554)	(437,351)
Accumulated contributions in excess of net periodic benefit cost	3,883	4,813	4,310	4,616	(2,216)	(28,360)	(172,909)	483,542	310,633
Net amount [surplus (deficit)] recognized in statement of financial position	1,468	2,308	113	4,638	(2,605)	(54,968)	(156,706)	29,988	(126,718)
December 31, 2022									
Fair value of plan assets	8,843	9,043	13,073	7,241	17,028	-	-	2,227,261	2,227,261
Benefit obligation	7,176	6,557	12,406	2,963	18,319	42,775	119,442	1,885,884	2,005,326
Funded status (plan assets less benefit obligations)	**1,668**	**2,485**	**668**	**4,278**	**(1,291)**	**(42,775)**	**(119,442)**	**341,379**	**221,937**
Prior service credit (cost)	-	-	-	-	-	-	(302)	-	(302)
Net gain (loss)	(2,422)	(2,563)	(3,543)	(510)	1,848	(14,595)	53,888	(188,959)	(135,071)
Accumulated other comprehensive income (loss)	(2,422)	(2,563)	(3,543)	(510)	1,848	(14,595)	53,586	(188,959)	(135,373)
Accumulated contributions in excess of net periodic benefit cost	4,090	5,048	4,211	4,788	(3,139)	(28,180)	(173,028)	530,338	357,310
Net amount [surplus (deficit)] recognized in statement of financial position	1,668	2,485	668	4,278	(1,291)	(42,775)	(119,442)	341,379	221,937
December 31, 2023									
Fair value of plan assets	8,801	9,043	12,802	7,135	18,789	-	-	2,268,460	2,268,460
Benefit obligation	6,806	6,213	11,608	2,650	19,369	41,907	119,604	1,909,851	2,029,455
Funded status (plan assets less benefit obligations)	**1,995**	**2,830**	**1,194**	**4,485**	**(580)**	**(41,907)**	**(119,604)**	**358,610**	**239,006**
Prior service credit (cost)	-	-	-	-	-	-	(328)	-	(328)
Net gain (loss)	(2,094)	(2,262)	(2,968)	(383)	1,837	(13,948)	49,893	(180,027)	(130,134)
Accumulated other comprehensive income (loss)	(2,094)	(2,262)	(2,968)	(383)	1,837	(13,948)	49,565	(180,027)	(130,462)
Accumulated contributions in excess of net periodic benefit cost	4,089	5,092	4,162	4,868	(2,417)	(27,959)	(169,169)	538,637	369,468
Net amount [surplus (deficit)] recognized in statement of financial position	1,995	2,830	1,194	4,485	(580)	(41,907)	(119,604)	358,610	239,006
Net gain (loss) on corporate books basis at December 31, 2023	(75)	(361)	(2,968)	(383)	1,837	(1,204)	45,897	(19,894)	26,003
Local books AOCI (loss) in excess of corporate books	**(2,019)**	**(1,901)**	**-**	**-**	**-**	**(12,744)**	**3,996**	**(160,133)**	**(156,137)**

Key Assumptions[1]	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB (EGD/UG)	Total Pension	Grand Total
Effective discount rate on benefit obligations	5.26%	5.26%	5.25%	5.16%	5.28%	5.26%	5.27%/5.27%		
Effective rate for interest on benefit obligations	5.20%	5.20%	5.19%	5.14%	5.23%	5.20%	5.23%/5.22%		
Effective discount rate for service cost	N/A	N/A	N/A	N/A	5.28%	N/A	5.27%/5.27%		
Effective rate for interest on service cost	N/A	N/A	N/A	N/A	5.23%	N/A	5.27%/5.27%		
Expected return on assets	5.00%	5.00%	3.00%	3.00%	4.20%	N/A	N/A		
Net expected return on assets	5.00%	5.00%	3.00%	3.00%	4.20%	N/A	N/A		
Increases in pensionable earnings	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	Ranges from 2.50% to 5.00% based on age	N/A		
Average wage index	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year	2.5% per year	N/A		
Mortality table	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B	100% CPM Private, with improvements based on scale CPM-B		

[1] Effective discount rates and interest rates disclosed are based on market conditior

Enbridge Gas Inc. - Projected US GAAP Corporate and Local Books Bases AOCI and applicable Amortizations (December 31, 2021 to December 31, 2023)

Company's Share US GAAP ('000s)	EI RPP	EGD RPP	Pension Choices	M&S	BU	Salaried
December 31, 2021						
Net gain (loss) on corporate books basis	13,618	(214,077)	(55,476)	(3,051)	(1,276)	(2,320)
Net gain (loss) on local books basis	13,618	(214,077)	(133,498)	(33,782)	(33,120)	(16,603)
Local books AOCI (loss) in excess of corporate books	-	-	(78,022)	(30,731)	(31,844)	(14,283)
December 31, 2022						
Amortization of net actuarial loss (gain) on corporate books basis	-	7,775	-	-	-	-
Amortization of net actuarial loss (gain) on local books basis	-	7,775	4,854	1,155	1,162	590
Local books amortization cost (credit) in excess of local books	-	-	4,854	1,155	1,162	590
Net gain (loss) on corporate books basis	79,451	(113,188)	25,224	(4,418)	(3,379)	(3,745)
Net gain (loss) on local books basis	79,451	(113,188)	(47,944)	(33,994)	(34,061)	(17,438)
Local books AOCI (loss) in excess of corporate books	-	-	(73,168)	(29,576)	(30,682)	(13,693)
December 31, 2023						
Amortization of net actuarial loss (gain) on corporate books basis	-	51	-	-	-	-
Amortization of net actuarial loss (gain) on local books basis	-	51	-	1,421	1,475	753
Local books amortization cost (credit) in excess of local books	-	-	-	1,421	1,475	753
Net gain (loss) on corporate books basis	83,266	(113,491)	25,032	(4,379)	(3,396)	(3,772)
Net gain (loss) on local books basis	83,266	(113,491)	(48,136)	(32,533)	(32,603)	(16,712)
Local books AOCI (loss) in excess of corporate books	-	**-**	**(73,168)**	**(28,154)**	**(29,207)**	**(12,940)**

The **local books** financial information is prepared from the perspective that the Legacy Spectra Plans continued as going concerns, without taking into account the February 27, 2017 merger with Enbridge. The **corporate books** financial information reflects a fresh start approach from the merger for the Legacy Spectra Plans. The fair value of assets and projected benefit obligation are the same between the local books and Enbridge's financial statements, however the amounts in the accumulated other comprehensive income accounts (AOCI) are not the same due to differences in the recognition of past costs and ongoing differences in recognition of actuarial gains and losses. Furthermore, the AOCI amounts will never converge unless the recognition approach (i.e. amortization calculation) is adjusted. Since the AOCI loss is larger on a local books basis, this will require an increase in the amounts currently recognized through P&L.

Rounding and scaling are applied as a final step, which may present reconciliation differences.

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Enbridge Gas Inc. - Projected US GAAP Corporate and Local Books E

Company's Share US GAAP ('000s)	Group 1	Group 3	EGD SERP	EGD SSERP	EI SPP	LSE SERP	OPEB	Total Pension	Grand Total
December 31, 2021									
Net gain (loss) on corporate books basis	(226)	(440)	(4,197)	22	(389)	(11,867)	12,038	(279,679)	(267,641)
Net gain (loss) on local books basis	(2,415)	(2,505)	(4,197)	22	(389)	(26,608)	16,478	(453,554)	(437,076)
Local books AOCI (loss) in excess of corporate books	(2,189)	(2,065)	-	-	-	(14,741)	4,440	(173,875)	(169,435)
December 31, 2022									
Amortization of net actuarial loss (gain) on corporate books basis	-	-	204	-	12	38	(922)	8,029	7,107
Amortization of net actuarial loss (gain) on local books basis	78	76	204	-	12	1,384	(1,153)	17,290	16,137
Local books amortization cost (credit) in excess of local books	78	76	-	-	-	1,346	(231)	9,261	9,030
Net gain (loss) on corporate books basis	(311)	(574)	(3,543)	(510)	1,848	(1,201)	49,680	(24,346)	25,334
Net gain (loss) on local books basis	(2,422)	(2,563)	(3,543)	(510)	1,848	(14,595)	53,888	(188,959)	(135,071)
Local books AOCI (loss) in excess of corporate books	(2,111)	(1,989)	-	-	-	(13,394)	4,208	(164,613)	(160,405)
December 31, 2023									
Amortization of net actuarial loss (gain) on corporate books basis	-	-	169	-	-	-	(3,731)	220	(3,511)
Amortization of net actuarial loss (gain) on local books basis	92	88	169	-	-	651	(3,944)	4,700	756
Local books amortization cost (credit) in excess of local books	92	88	-	-	-	651	(213)	4,480	4,267
Net gain (loss) on corporate books basis	(75)	(361)	(2,968)	(383)	1,837	(1,204)	45,897	(19,894)	26,003
Net gain (loss) on local books basis	(2,094)	(2,262)	(2,968)	(383)	1,837	(13,948)	49,893	(180,027)	(130,134)
Local books AOCI (loss) in excess of corporate books	**(2,019)**	**(1,901)**	**-**	**-**	**-**	**(12,744)**	**3,996**	**(160,133)**	**(156,137)**

The **local books** financial information is prepared from the perspective tha
27, 2017 merger with Enbridge. The **corporate books** financial informatior
assets and projected benefit obligation are the same between the local boc
comprehensive income accounts (AOCI) are not the same due to differenc
losses. Furthermore, the AOCI amounts will never converge unless the rec
books basis, this will require an increase in the amounts currently recognizi

Rounding and scaling are applied as a final step, which may present recon

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, Appendix A, Page 1, Table 1, Reconciliation of Utility O&M Schedule, 2022 & 2023 Results

Question(s):

a) Please confirm Lakeside Gas provides certain services to Enbridge Gas such as meter exchanges.

b) Is Lakeside Gas an affiliate of Enbridge Gas?

c) Are the costs of services provided to Enbridge Gas by Lakeside Gas included in Line 4, Outside Services or in Line 13, Corporate Shared Services?

Response:

a) Confirmed. In addition to meter exchanges, Lakeside Gas also provides initial and safety inspections, meter unlocks, service relights, emergency response, etc.

b) Confirmed. Lakeside is an affiliate of Enbridge Gas.

c) Lakeside Gas costs are included in outside services in Line 4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, page 23, paragraph 2

Preamble:

"Based on 2021 external contractor costs Enbridge Gas was expecting to pay approx. $34 per locate in 2023, however the actual cost paid for a locate rose to $72 a 111% increase over expectation. The increase in cost was a direct result of Bill 93 which imposed a five-business-day deadline for completing standard locate requests and introduced administrative penalties for failing to comply".

Question(s):

a) Does Enbridge Gas outsource all locate work or are some locates performed by its employees?

b) Does Enbridge Gas use a single contractor for locates or does it use multiple contractors? If Enbridge Gas uses one contractor for all locates, was there a competitive bidding process to award the contract? If multiple contractors are used, do their rates vary or do they all charge same rates?

c) Does Enbridge Gas incur internal administrative costs per locate and if so, are these included in the GOCA deferral account?

Response:

a) Enbridge Gas outsources over 99% of the more than 1 million locates completed annually.

b) Enbridge Gas uses multiple contractors and is a member of the Locate Alliance Consortium (LAC). LAC is a group of Ontario infrastructure owners who engage in a RFP processes with Locate Service Providers (LSP) and benefit from multi-utility discount pricing structures. Multiple contractors are used, and rates vary by contractor, geographical area, and number of utilities located.

c) Enbridge Gas does incur internal administrative costs per locate but these were not included in the Getting Ontario Connected Act (GOCA) deferral account.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit C, Tab 1, Page 24, Paragraph 6

Preamble:

"Bill 93 has directly resulted in incremental costs outside of base rates in two areas: the cost of the locate itself, and in vital main standby (VMS) costs – a locate-related service requiring an experienced locator skillset and therefore provided by the same locate service providers (LSP)."

Question(s):

a) Please explain what Vital Main Standby (VMS) is and is it an activity specific to Enbridge Gas.

b) Please explain how and why locates performed for VMS differ from other locates?

Response:

a) Vital main standby (VMS) is part of the locating process for Enbridge Gas high risk assets. The program involves having a Locate Service Provider (LSP) resource onsite during 3rd party excavations on these high-risk assets to ensure that excavators adhere to vital main excavation requirements. VMS ensures public safety, prevents pipeline damages and energy outages, and is a key component of the Enbridge Gas damage prevention program. This activity is considered an industry best practice and is not unique to Enbridge Gas.

b) VMS locates differ from other locates as VMS locates are only those locates that are delivered for high risk/high consequence assets. Vital main pipelines are typically large diameter pipelines under very high operating pressures and are therefore treated differently in the locate process. When 3rd party excavation is identified around vital assets, the locate process involves excavator interaction with Enbridge Gas and if required, a vital main standby during excavation as described in the response to part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit C, Tab 1, page 25, paragraph 8

Preamble:

"As a result of LSPs onboarding additional locators and locator wage increases, locating costs are up significantly for Enbridge Gas. Quite simply, Bill 93 required Enbridge Gas to shave an average of 10 days off its locate delivery time and the only way to achieve this was to have more locators. This coincided with LSP union negotiations where labour rates increased significantly to match the new industry skillset requirements and to attract/retain more specialized talent. This increase in locators and rates have caused the Enbridge Gas cost per locate to double."

Question(s):

a) Did Enbridge Gas obtain the information from LSPs in the quoted paragraph in written form? If the answer is yes, please file copies of all letters, e-mails, and text messages from LSPs to Enbridge Gas that explain the reasons for the cost increase? If the answer is no, how did Enbridge Gas obtain this information?

b) Did Enbridge Gas dispute any invoices it received from LSPs? If the answer is yes, please describe each dispute and file all letters, e-mails, and text messages from Enbridge Gas to LSPs disputing invoices. If the answer is no, please explain why not.

Response:

a) The negotiations and communications with locate service providers (LSPs) were typically not specific to Enbridge Gas. Enbridge Gas is a member of the Locate Alliance Consortium (LAC) which consists of many Ontario infrastructure owners who negotiate locating rates with LSPs. In 2022, LAC went through multiple rounds of contract extension and pricing negotiations with the existing LSPs to establish appropriate unit rates based on Bill 93 legislation. LSP labour union rates increased significantly due to the need to compete for and retain talent with a requisite skillset.

b) Enbridge Gas has a comprehensive internal invoicing review and approval process for all external contractors. In addition, beginning in 2023 Enbridge Gas utilized external consultants to audit monthly LSP invoicing. Enbridge Gas has disputed LSP invoices and has recovered over $30k over the past 7 months.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit C, Tab 1, page 26, paragraph 13

Preamble:

“Actual 2021 locating costs were $34.5 million. To incorporate inflationary impacts,the PCI values for 2022 and 2023 were applied resulting in an inflation adjusted cost of $36.2 million6. After adjusting for 2023 actual locate volumes, the calculated annual base locate cost for 2023 is $33.1 million. Please refer to Table 1 outlining the calculations.”

Question(s):

a) Please confirm that $33.1 million is an estimate of the increase of locate costs because of Bill 93 and not the actual increase.

b) What was the total actual amount of locate costs for 2023 including the increase due to Bill 93?

Response:

a) $33.1 million does not represent the estimated or actual increase. It is the calculated annual cost of what Enbridge Gas locates were expected to cost in 2023 without Bill 93 in place.

b) The actual cost for 2023 locates and vital main stand-by (VMS) was $74.1 million (locates = $65.8M and VMS = $8.3M).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit C, Tan 1, page 27, Table 2, VMS Costs, and paragraph 15

Preamble:

"The calculated annual base locate and VMS costs for 2023 were $33.1 million and $4.9 million respectively.

Question(s):

a) Please reconcile the text quoted in the preamble from paragraph 15 with the figures shown in Table 2.

b) Please confirm that the amount listed in Line 7 is an estimate and provide the 2023 actual amount.

Response:

a) $33.1 million reconciles with Table 1, Line 7 and $4.9 million reconciles with Table 2, Line 7.

b) Line 7 in both Table 1 and Table 2 is a calculation of what Enbridge Gas expected to spend on locates and vital main standby (VMS) in 2023. The actual amount spent for 2023 is the sum of Line 1 of Table 3 ($7.7M + $58.1M = $65.8M) and Line 1 of Table 4 ($0.9M + $7,4M = $8.3M), totaling $74.1M ($65.8M + $8.3M).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit D, Tab 1, Attachment 2, page 1

Preamble:

"The purpose of the account is to record the incremental costs associated with the Fugitive Emissions Investigation Plan. The revenue requirement will include incremental operating costs as well as costs associated with any required capital investment, including return on rate base, depreciation expense, and associated income taxes. Incremental costs are related to the implementation of measurement technologies, configuration of IT systems, incremental staffing, consulting support and other miscellaneous costs, including training, conferences, and memberships associated with methane measurement technologies and methodologies."

Question(s):

The quoted description of the account mentions "incremental costs associated with the Fugitive Emissions Plan." That implies that there are also non-incremental costs such as the annual leak survey. Does Enbridge have an annual leak survey program? If the answer is yes, what was the amount spent on it in 2023? If the answer is no, please explain why not.

Response:

Enbridge Gas Inc. performs annual leak surveys in accordance with government regulations, including the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*, and industry accepted best management practices, including CSA Z662.

Survey type and frequency differ based on the type of asset being surveyed.

For example:

a) Compressor stations are surveyed 3x/year, using optical gas imaging to detect leaks, in accordance with federal regulatory requirements. Enbridge Gas additionally quantifies leak flow rate through the use of a Hi-Flow sampler.

b) A subset of distribution pipelines and assets are surveyed annually (with survey frequency differing for different asset types) by way of a foot patrol, during which a leak survey is conducted. A flame ionization gas detector is utilized during the foot patrol in order to detect if leaks are present. Leak flow rate is not quantified as part of the distribution leak survey program.

   In addition to scheduled annual leak surveys, ad-hoc surveys are triggered by any customer calls for smell of gas, fire, fumes, or TSSA investigations. These trigger a complete leak survey check and inspection by licensed gas fitters.

The approximate annual costs associated with Enbridge Gas's existing leak survey program are approximately $5 million for surveys and inspections. This does not include the costs associated with responding to ad-hoc customer calls, or the costs associated with repairing leaks that are found during annual surveys. Enbridge Gas's current leak survey program is compliant with regulatory requirements and applies industry-standard methods.

The proposed Fugitive Emissions Measurement Administration Deferral Account (FEMADA) reflects the incremental costing required to implement the investigation plan that Enbridge Gas prepared, as agreed to in the 2024 Phase 1 Rebasing application[1] This level of fugitive emissions direct measurement goes above and beyond current regulatory requirements and standard practices.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.11.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit A, Tab 3, Appendix A, pg. 1, line 1 and Exhibit D, Tab 1, pg. 1-2

Preamble:

Paragraph 4 and 5 in the second reference account for $9.6M of the $18.7M the company is seeking recovery. We would like to understand the other contributing factors to the other half and the escalation from $8.1M in 2022.

Question(s):

Please provide and quantify the other significant contributing factors to the remaining $9.1M of recovery.

a) Please provide a comparison of this year's contributing factors to those in 2022.

Response:

Please see Exhibit D, Tab 1, Schedule 1, col. 7 for all of the contributing factors of the $18.7 million balance. Paragraphs 4 and 5 at Exhibit D, Tab 1, page 1 describe the factors relating to $9.6 million of the total balance. The remaining $9.1 million is based on three factors, including $13.2 million of higher than forecasted transportation prices, $1.6 million of higher than forecasted Federal Carbon costs, partially offset by $5.7 million lower than forecasted Dawn T Service costs.

a) Please see Table 1.

Table 1
2023 Deferral Breakdown vs. 2022 Deferral Breakdown

Line No.	Contracted Union Capacity ($ millions)	Col. 1 Balance in the 2023 S&TDA (1)	Col. 2 Balance in the 2022 S&TDA (2)	Col. 3 Difference (3)
1	Union Gas Dawn to Lisgar	(0.3)	(0.3)	0.0
2	Union Gas Dawn to Parkway	(12.0)	(9.6)	(2.4)
3	Union Gas Dawn to Parkway - M12X	(1.0)	(0.7)	(0.3)
4	Union Gas F24 T	0.0	0.0	0.0
5	Union Transmission Costs	(13.2)	(10.6)	(2.6)
6	Dawn T Service Costs	5.7	3.8	1.9
7	Federal Carbon Costs	(1.6)	(1.5)	(0.1)
8	Union & Third Party Market Based Storage	(3.7)	(1.3)	(2.4)
9	Deferral Disposition - UG	(5.9)	1.5	(7.4)
10	Total	(18.7)	(8.1)	(10.6)

Notes:
(1) EB-2024-0125, Exhibit D, Tab 1, Schedule 1, Col. 7
(2) EB-2023-0092, Exhibit D, Tab 1, Schedule 1, Col. 7
(3) Col. 1 - Col. 2

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit A, Tab 3, Appendix A, pg. 1, line 2 and Exhibit D, Tab 1, pg. 3-4

Preamble:

In the second reference, EGI evidence states: Transactional services optimization in the Enbridge Gas rate zones is higher than what has been included in rates due to changing market dynamics. The majority of this increase results from the increase in the Dawn-Waddington spread. This spread is influenced by the lack of pipeline infrastructure serving US Northeast markets.

We would like to understand better the breakdown of the components of the transactional services revenues.

Question(s):

Please populate the following table for both 2022 and 2023 for the EGD Zone:

Month	Storage-based Revenue	Transportation-based Revenue	Transportation to Waddington	Other Transportation

a) Please describe the other significant contributions to revenue for 2023 with a comparison to 2022

Response:

Please see Table 1 for 2022 and 2023 transactional services optimization revenue detail for the EGD Rate Zone.

Table 1
EGD Rate Zone Monthly Transactional Services Optimization Revenue

Line No.	Particulars ($000's)	2022				2023			
		Storage-Based	Transportation-Based	Waddington Exchanges	Other	Storage-Based	Transportation-Based	Waddington Exchanges	Other
1	January	-	11,807.6	11,087.2	729.1	-	11,011.5	10,942.8	68.7
2	February	-	7,736.2	7,133.0	611.9	-	15,437.4	15,201.5	235.9
3	March	-	3,255.5	2,680.2	584.0	-	10,605.9	10,392.0	214.0
4	April	-	435.9	289.3	155.3	-	190.2	10.3	179.8
5	May	-	326.3	201.5	133.5	-	240.4	14.4	226.0
6	June	-	309.1	181.9	135.9	-	256.2	13.6	242.5
7	July	-	732.1	520.2	220.6	-	441.8	145.4	296.5
8	August	-	635.6	451.6	192.7	-	293.5	10.6	282.9
9	September	-	201.7	59.4	151.0	-	326.9	80.8	246.1
10	October	-	233.0	108.1	133.6	-	252.5	11.2	241.3
11	November	-	10,538.3	10,442.1	104.9	-	10,481.0	10,468.2	12.8
12	December	-	11,589.4	11,482.3	115.8	-	9,983.6	9,676.3	307.3
13	Total	-	47,904.8	44,636.7	3,268.1	-	59,520.9	56,967.1	2,553.8

NOTES:
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 2022 and 2023.

a) As there was no increase in the amount of new pipeline capacity into the US Northeast in 2023, significant contributions to revenue in 2023 were similar to those experienced in 2022. More specifically, during both January 2022 and January 2023, there was very cold weather in the US Northeast which drove up the price of gas at Waddington for a number of days.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit A, Tab 3, Appendix A, lines 18 & 23 and Exhibit E, Tab 1, pg. 6-11

Question(s):

Please populate the same table shown in 2 for 2022 and 2023 for the UGL Zone.

a) Please compare and provide the difference between EGD and UGL results for 2023 for storage & transportation-based revenue.

b) How is revenue treated for non-peak storage sold short-term including additional cycling rights?

Response:

Please see Table 1 for 2022 and 2023 transactional services optimization revenue detail for the Union Rate Zones.

Table 1
Union Rate Zones Monthly Transactional Services Optimization Revenue

Line No.	Particulars ($000's)	2022				2023			
		Storage-Based	Transportation-Based	Waddington Exchanges	Other	Storage-Based	Transportation-Based	Waddington Exchanges	Other
1	January	-	1,229.5	730.8	498.7	-	1,083.0	-	1,083.0
2	February	-	1,240.2	416.3	823.9	-	1,462.8	-	1,462.8
3	March	-	1,081.0	485.9	595.1	-	985.4	-	985.4
4	April	-	387.2	(52.8)	440.0	-	288.8	2.0	286.8
5	May	-	451.3	-	451.3	-	333.2	(0.0)	333.2
6	June	-	441.7	-	441.7	-	416.3	39.9	376.5
7	July	-	538.6	79.4	459.2	-	334.5	13.8	320.7
8	August	-	453.1	41.8	411.3	-	338.7	0.0	338.7
9	September	-	409.8	(0.0)	409.8	-	344.8	6.5	338.3
10	October	-	482.7	-	482.7	-	288.0	-	288.0
11	November	-	780.7	-	780.7	-	1,027.3	895.5	131.7
12	December	-	1,114.0	-	1,114.0	-	1,089.0	877.2	211.7
13	Total	-	8,609.9	1,701.5	6,908.4	-	7,991.8	1,835.0	6,156.8

a) 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.

b) Short-term storage-based revenues generated by optimizing Union Rate Zones assets (including peak storage, non-peak storage, and additional cycling rights) are recorded in and are subject to deferral under Account No. 179-70 Short-Term Storage and Other Balancing Services – Union Rate Zones.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 4, pg. 1

Question(s):

Please provide the content of footnote (1).

a) If not included in the response to the footnote, please describe the sources of Other Income in Line 11.

b) Please explain the debit vs. credit between 2022 and 2023.

Response:

The footnote in Exhibit B, Tab 2, Schedule 4, page 1 indicates the following: *Includes Gain(Loss) on foreign exchange and Gain(Loss) on disposition of assets.*

a) Please see Table 1 for the sources of Other Income in Line 11.

Table 1
Other Income – Utility 2023

Line No.	Particulars ($ millions)	Amount
		(a)
1	Gain on sale of assets	4.1
2	Foreign exchange gains and other income	3.0
3	Total	7.1

b) As noted above in part a), Other Income in 2023 totaled a net $7.1 million credit in revenue where gains on both sale of assets and foreign exchange were realized. In comparison, in 2022 Other Income totaled a net ($2.1) million debit made up of foreign exchange losses net of other income of $5.7 million offset partially by gain on sale of assets of $3.6 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, pg. 2, line 1

Preamble:

We would like to understand better the components of Compensation and Benefits and the escalation in 2023.

Question(s):

Please provide a breakdown of the components of Line 1 ensuring that salaries, performance increases, severances, benefits and other significant categories are disaggregated.

a) Please explain the reasons for the 2023 escalation of the components.

Response:

The breakdown of the components of Compensation and Benefits in line 1 for 2023 is as follows:

1. Compensation: $293.3 million
2. Short-term incentive pay; and Long-term incentive pay: $59.5 million
3. Benefits: $63.9 million
4. Pension: $9.2 million

a) Compensation and Performance increases are in accordance with Enbridge Gas's compensation program with a small portion of the increase due to the promotion of employees.

   Benefits increased primarily due to inflationary increases and higher salaries from merit increases and higher headcount. Prescription drugs, dental, paramedical, eyeglasses etc. are also subject to the global inflation experienced in the economy, post COVID.

   Pension costs increased due to higher interest rates and lower than expected return on pension assets.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, pg.3 & 5, Table 2

Preamble:

We would like to understand more about the overhead capitalization impact including allocations to Corporate.

Question(s):

Please provide a comprehensive breakdown of all projects, initiatives and other categories to which allocations were made to CSS. Please quantify:

a) the rate used for both CSS and non-CSS
b) the total FTE's in each of the departments provided in paragraph 6
c) other factors to justify theses allocations

Response:

As discussed at Exhibit B, Tab, 3, Schedule 1, paragraph 6, Corporate Shared Services (CSS) costs are charged to Enbridge Gas based on appropriate cost allocation in relation to the services received under the Enbridge Inc. Central Functions Cost Allocation Methodology (CFCAM). Costs are not specifically allocated based on project, initiatives and other categories. Detail on the CFCAM can be found in the Phase 1 2024 Rebasing Application.[1]

a) Background on the rates used in overhead capitalization can be found in the Phase 1 2024 Rebasing Application.[2] There are different rates used in each component of capitalization methodology. In relation to the Overhead Capitalization as per Table 2, the average rate calculated using capitalization divided by gross cost for CSS is 25.9%. The average rate calculated using non-capitalization divided by gross cost for Non CSS is 16.9%.

[1] EB-2022-0200, Exhibit 4, Tab 4, Schedule 3, pars.46 to 51.
[2] EB-2022-0200, Exhibit 2, Tab 4, Schedule 2,

b) FTE count for CSS does not drive the CFCAM as CSS costs are based on allocation received for the services provided to Enbridge Gas as either direct charge cost, directly attributable allocation or indirect cost allocation as described in detail in the Phase 1 2024 Rebasing Application.[3]

c) The overhead capitalization allocation to CSS is based on harmonized overhead capitalization methodology discussed in the Phase 1 2024 Rebasing Application[4] from both Shared Services Cost and Pension and Benefits Costs.

[3] EB-2022-0200, Exhibit 4, Tab 4, Schedule 3, Attachment 3.
[4] EB-2022-0200, Exhibit 2, Tab 4, Schedule 2, pp.11-13.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, pg.3 & 5, Table 2

Preamble:

We would like to understand more about the overhead capitalization impact including allocations to Corporate.

Question(s):

Please provide the answers to question 6 for 2022.

Response:

Please see the response at Exhibit I.FRPO-6 parts b) and c).

Background on the rates used in overhead capitalization can be found in the 2024 Rebasing Phase 1 application[1]. There are different rates used in each component of capitalization methodology.

The 2022 average rate calculated using capitalization divided by gross cost for Corporate Shared Services (CSS) is 23.3%, The 2022 average rate calculated using non-capitalization divided by gross costs for Non-CSS is 19.8%.

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

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, pg.3 & 5, Table 2

Preamble:

We would like to understand more about the overhead capitalization impact including allocations to Corporate.

Question(s):

Please provide the contents for Table 2 for each of the years 2019 to 2022.

Response:

Exhibit B, Tab 3, Schedule 1, Table 2 has been updated with contents for 2019 to 2022.

Table 2
Total Overhead Capitalization Impact on O&M

Line No.	Categories	2019	2020	2021	2022	2023
		($M)	($M)	($M)	($M)	($M)
1	CSS-related Capitalization	(104.8)	(105.0)	(96.7)	(86.7)	(95.7)
2	Capitalization on Non-CSS	(119.5)	(119.5)	(138.2)	(183.1)	(209.4)
3	Total Overhead Capitalization	(224.3)	(224.5)	(234.9)	(269.7)	(305.0)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 2, pg. 7

Question(s):

Please provide the meter change units for each of 2019 to 2023 for each rate zone.

Response:

Table 1
Total Number of Meter Exchanges

Line No.	Rate Zone	2019	2020	2021	2022	2023
1	EGD	59,585	59,107	55,624	69,351	91,974
2	UG	73,934	54,856	44,055	62,584	72,388
3	Total Number of Meter Exchanges	133,519	113,963	99,679	131,935	164,362

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1, pg. 4 and
EB-2024-0111 Exhibit 1, Tab 13, Schedule 2, pg. 6

Preamble:

In the second reference, EGI evidence states: Prior to 2019, EGD did not allocate any of its materials and supplies inventory to unregulated storage operations, which continued through the deferred rebasing term for the EGD rate zone.

Question(s):

Using the proposed approach to the rectification of this practice in the Phase 2 evidence, please provide the annual amount of costs that would have been allocated away from the utility to the non-utility storage for each year in the deferred rebasing period

Response:

The reference to materials and supplies within EB-2024-0111, Exhibit 1, Tab 13, Schedule 2, page 6 is in relation to the proposed inclusion of materials and supplies inventory as part of working capital within Enbridge Gas's rate base. This is not in relation to materials and supplies expense as recognized in O&M, as referenced in Exhibit B, Tab 3, Schedule 1, page 4. The allocation of O&M expense related to materials and supplies is proposed to occur as part of all other cost allocation as described in section 2.6[1].

Regardless of the above, Enbridge Gas has noted[2] that during the deferred rebasing period 2019-2023, that the prior approved methodologies for unregulated storage cost allocation of both EGD and Union were followed, and that the proposed harmonized methodology was brought forward for approval effective January 1, 2024.

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[1] EB-2024-0111, Phase 2 Exhibit 1, Tab 13, Schedule 2, p.9.
[2] EB-2024-0111, Phase 2 Exhibit 1, Tab 13, Schedule 2, p.3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 1, pg. 8

Question(s):

Please provide the specific reference to the rebasing decision that EGI is relying upon for this proposed recovery.

a) How much incremental capital was added to ratebase through this policy alignment over the deferred rebasing period.
b) What is the revenue requirement associated with this incremental capital for each year in the period from 2024 to 2028.

Response:

Please see the response at Exhibit I.PP-4 for the background of the approval of Enbridge Gas's proposal through the OEB Decision on Settlement Proposal dated August 17, 2023 in the 2024 Phase 1 Rebasing application[1]. Further to this, Enbridge Gas notes that in its pre-filed evidence in the 2024 Phase 1 Rebasing application, the Company stated the following:

> As the final balances are not known at this time for all the accounts, Enbridge Gas is proposing disposition on an interim basis[2]. Enbridge Gas will seek final disposition of the D&VA balances, calculated as the difference between actual balances as of December 31, 2023, and balances approved for disposition as part of this Application, within the Company's 2023 annual earnings sharing and D&VA disposition proceeding.[3]

[1] EB-2022-0200
[2] Enbridge Gas is seeking final disposition of the Impacts Arising from the COVID-19 Emergency Deferral Account, Transitional Impact of Accounting Changes Deferral Account, and Transitional Pension Balance. The remaining accounts proposed for disposition as part of this Application are on an interim basis.
[3] EB-2022-0200, Exhibit 9, Tab 2, Schedule 1, p.1.

Accordingly, as noted at Exhibit I.PP-4, the accounting policies and treatment of disposal of balances as proposed were settled upon by all parties and approved by the OEB within this Decision on Settlement Proposal.

a) On a cumulative basis during the deferred rebasing period, Enbridge Gas capitalized an incremental $24.2 million in relation to the implementation of the harmonized overhead capitalization policy.

b) The associated revenue requirement of the above in part a) is approximately $2.3 million on average per year from 2024 through 2028.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 1, pg. 14-15 and Table 1 & 2

Preamble:

EGI evidence states: *The balance in the 2023 IRP Operating Costs Deferral Account that is being requested for clearance within this proceeding is a debit of $3.081 million, plus forecast interest of $0.247 million, for a total debit of $3.328. This amount is attributable to incremental Enbridge Gas staff salaries including expenses for IRP related work performed in 2023, the implementation of Integrated Resource Plan Alternatives (IRPA(s)) to defer a project in Kingston and non-labour costs such as consulting and legal costs. The OEB in its IRP Decision approved "incremental IRP administrative costs required to meet the increased workload related to IRP"1 … 'be treated as expenses and recorded in this account [operating costs deferral account]."*2

Question(s):

Please provide a yearly breakdown of the costs allocated using the categories described in the above evidence reference.

a) Specific to the non-labour costs, please provide:
   i) The yearly internal and external costs allocated
   ii) The specific engagements of outside agencies and their tasks and deliverables

Response:

a)
   i) All non-labour costs in Table 1 are external costs.
   ii) For each non-labour line item, the outside agency and tasks/deliverables is provided below:

East Kingston Creekford Rd Project

- Outside agency: Compression Technology Corp
- Tasks/deliverables: Compressed natural gas injection

<u>Posterity Group</u>

- Outside agency: Posterity Group
- Tasks/Deliverables:
  a) Completing a data refresh: This included updating and recalibrating the base year data and reference case growth forecast to the most recent available data.
  b) Recalibrating end-use load shapes at a sector or rate zone level to align with modeled design temperatures and exploring how different measures impact base loads versus heating loads and the impact on annual versus peak hour savings.
  c) Refinement of the selection of ETEE measures and program costs to better reflect differences in objectives between DSM and IRP.
  d) Review of different scenarios (i.e., reference case, DSM business-as-usual, technical potential, etc.) and the methodology and assumptions behind each, such as net-to-gross (NTG), optimizing costs based on annual versus peak.

<u>Stakeholder Engagement:</u>

- Outside agency: Survey Monkey
- Tasks/deliverables: Subscription cost for webinar follow up survey.

- Outside agency: Balsam Promotion
- Tasks/deliverables: Promotional Items for conferences including printed materials.

- Outside agency: Ricoh
- Tasks/deliverable: Print materials for conferences.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 1, pg. 14-15 and Table 1 & 2

Preamble:

EGI evidence states: *The balance in the 2023 IRP Operating Costs Deferral Account that is being requested for clearance within this proceeding is a debit of $3.081 million, plus forecast interest of $0.247 million, for a total debit of $3.328. This amount is attributable to incremental Enbridge Gas staff salaries including expenses for IRP related work performed in 2023, the implementation of Integrated Resource Plan Alternatives (IRPA(s)) to defer a project in Kingston and non-labour costs such as consulting and legal costs. The OEB in its IRP Decision approved "incremental IRP administrative costs required to meet the increased workload related to IRP"1 … 'be treated as expenses and recorded in this account [operating costs deferral account]."2*

Question(s):

Using the role descriptions in Table 2, from timesheets or other documentation, the percentage allocation to IRP in each of 2021, 2022 and 2023.

a) Please provide the total amounts associated with the salaries for the above years

b) Please provide the salary actuals in O&M for DOE staff for the above years

Response:

a) and b)

Table 1 provides the number of FTE positions associated with IRP. Each identified FTE allocates 100% of their time to IRP; however, the table below provides the percentage allocation of each FTE in 2022 and 2023 based on the months that the FTE was in place throughout the year. The total amounts for salary and loadings respectively per year are provided.

2021 has not been provided as it would provide for the ability to discern personal salary information due to the low FTE allocation in that year.

The salary actuals for DOE staff have not been provided separately as it would provide for the ability to discern personal salary information due to the low number of FTEs for these years

Table 1
FTE Positions Allocated to IRP

Line No.	Role	Department	Number of FTEs 2022	% Allocation for 2022	Number of FTEs 2023	% Allocation for 2023
1	Senior Advisor	Community Engagement	1	92	1	100
2	Advisor	Community Engagement	1	25	1	83
3	Senior Advisor	Distribution Optimization Engineering (DOE)	1	92	1	100
4	Engineer	DOE	1	92	1	100
5	Supervisor	DOE	1	42	1	100
6	Advisor	IRP	1	58	1	100
7	Advisor	IRP	1	92	1	100
8	Specialist II	Asset Management	1	92	1	67
9	Senior Advisor	DSM	1	92	1	100
10	Senior Advisor	Regulatory	1	50	1	100
11	Senior Advisor	Regulatory	1	50	1	100
12	Engineer	Storage & Transmission	0	0	0.5	21
13	Advisor	Municipal Energy Solutions	0	0	1	75

Table 1 (continued)
FTE Positions Allocated to IRP (continued)

Line No.	Role	Department	Number of FTEs 2022	% Allocation for 2022	Number of FTEs 2023	% Allocation for 2023
14	Advisor	Municipal Energy Solutions	0	0	1	67
15	Specialist	Finance	1	17	1	100
16	Senior Advisor	Finance	1	17	1	100
17	Director	IRP	0.5	50	0.5	50
Total FTEs			13.5	8.6	16	14.6
Total Salaries ($ M)				$ 0.997		$ 1.719
Total Loadings ($M)				$ 0.765		$ 0.948

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 1, pg. 19-20

Preamble:

EGI evidence states: *The East Kingston Creekford Rd Reinforcement project was a planned $24.3 million capital reinforcement. Enbridge Gas determined that this project could be deferred by implementing a supply side IRP alternative in the form of CNG beginning in 2022. Without the CNG injection, the Kingston system was anticipated to fall below its minimum pressure requirements as early as the Winter of 2022/2023. An agreement for CNG in 2022 ensured Enbridge Gas maintained a safe and reliable system for customers in the Kingston project service area. The CNG agreement was executed July 1, 2022, for the winters of 2022/2023 and 2023/2024 to ensure an in-service date of December 1, 2022. The contracted CNG service is an enabling payment to a competitive service provider, where Enbridge does not own the asset, per the IRP Decision EB-2019-0091. The 2022 charges for the CNG Agreement were approved for recovery in the IRP Operating Costs Deferral Account and the $0.278 is the 2023 cost of the CNG agreemen*t.

Question(s):

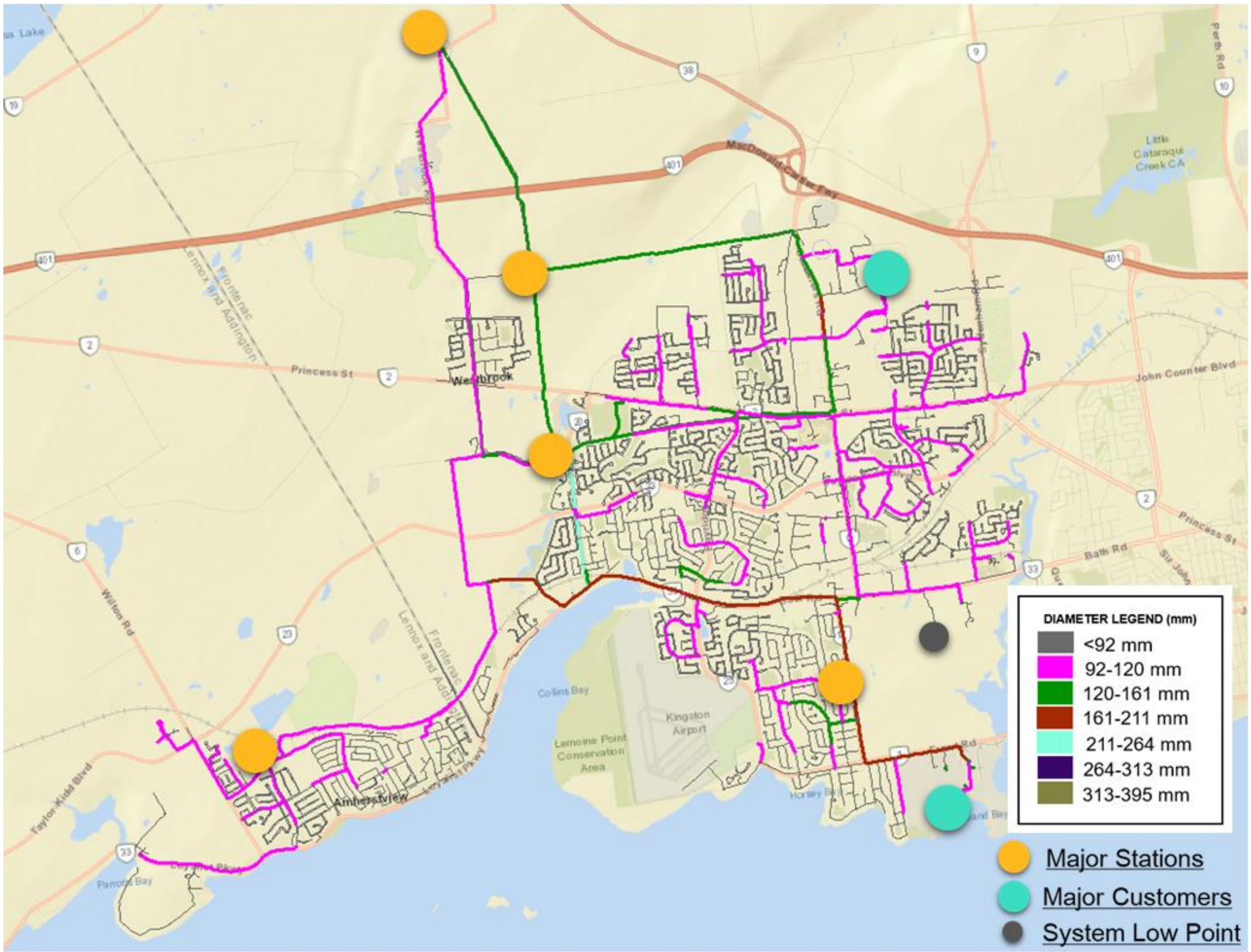
Please provide a major main map and network analysis showing pressures in the system including, specifically, the low point and location of contract customer for:

a) Winter of 2022/23 prior to CNG
b) Winter of 2022/23 after planned CNG
c) Winter of 2022/23 after contract reduction implemented in Nov. 2022

Response:

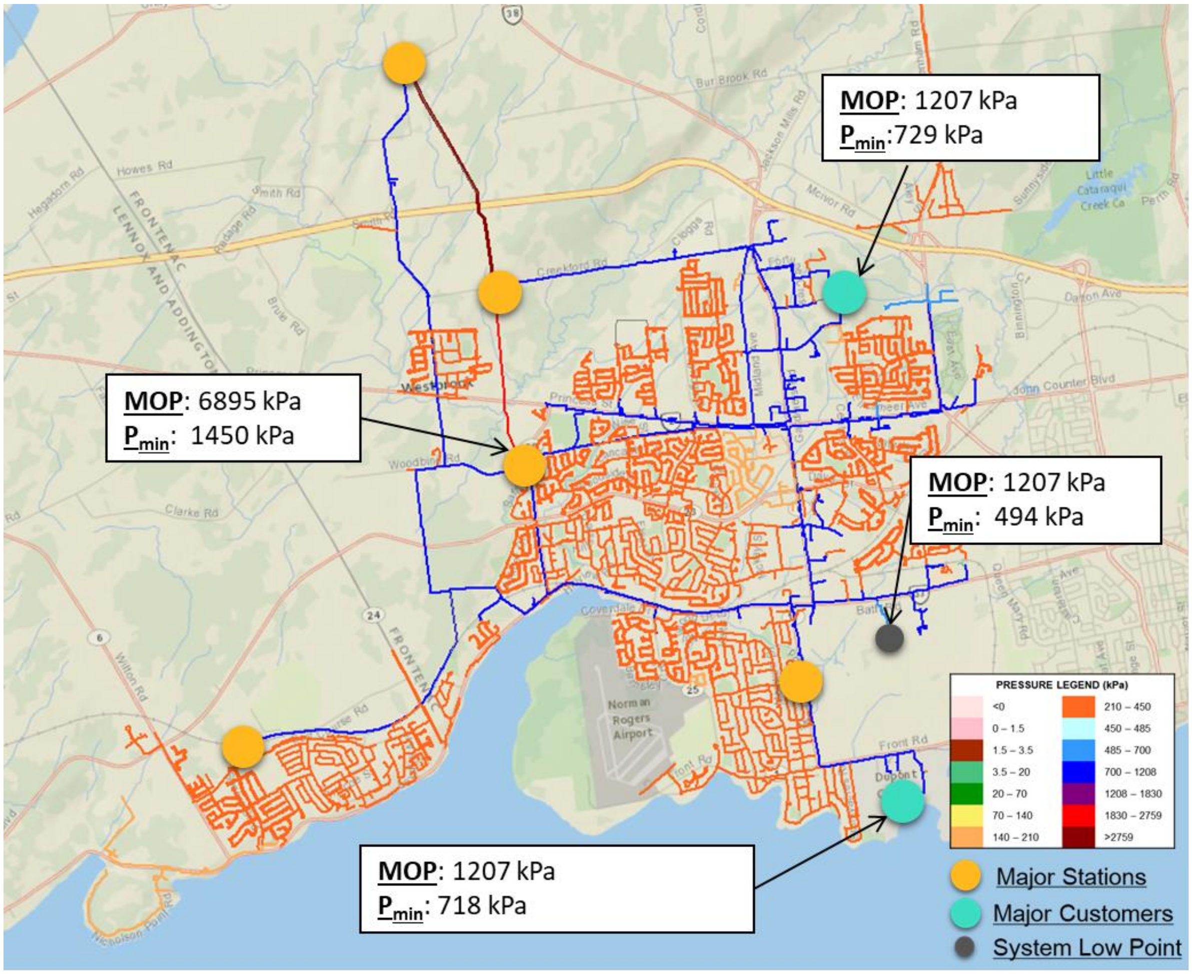
All maps and pressures herein have been provided based on modeled conditions for the 2022/2023 Winter Condition. Modeled pressures do not include any reserved customers forecasted to attach in future years.

Figure 1: Major Main Map



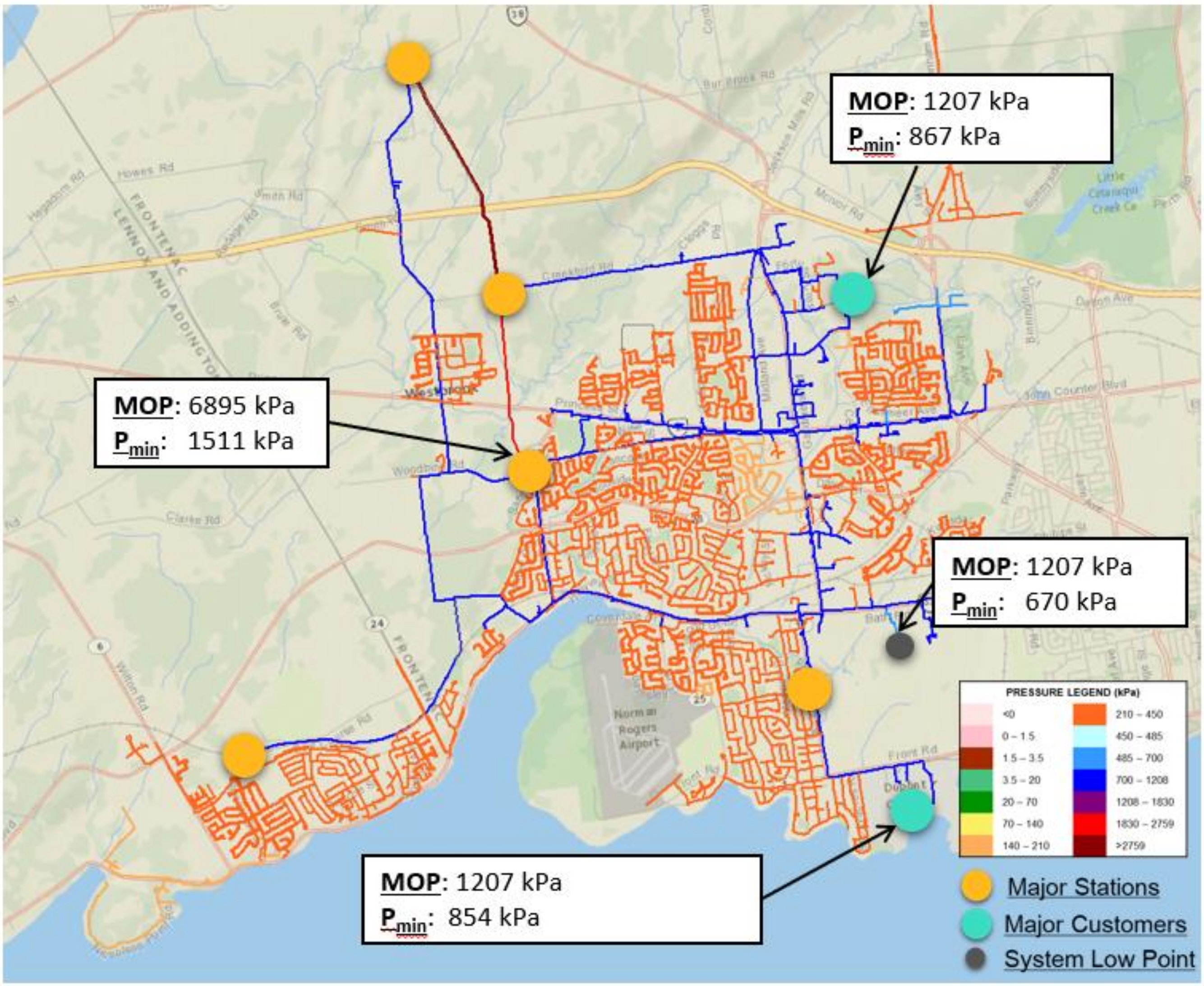
a)

Figure 2: System Map - Winter of 2022/23 prior to CNG



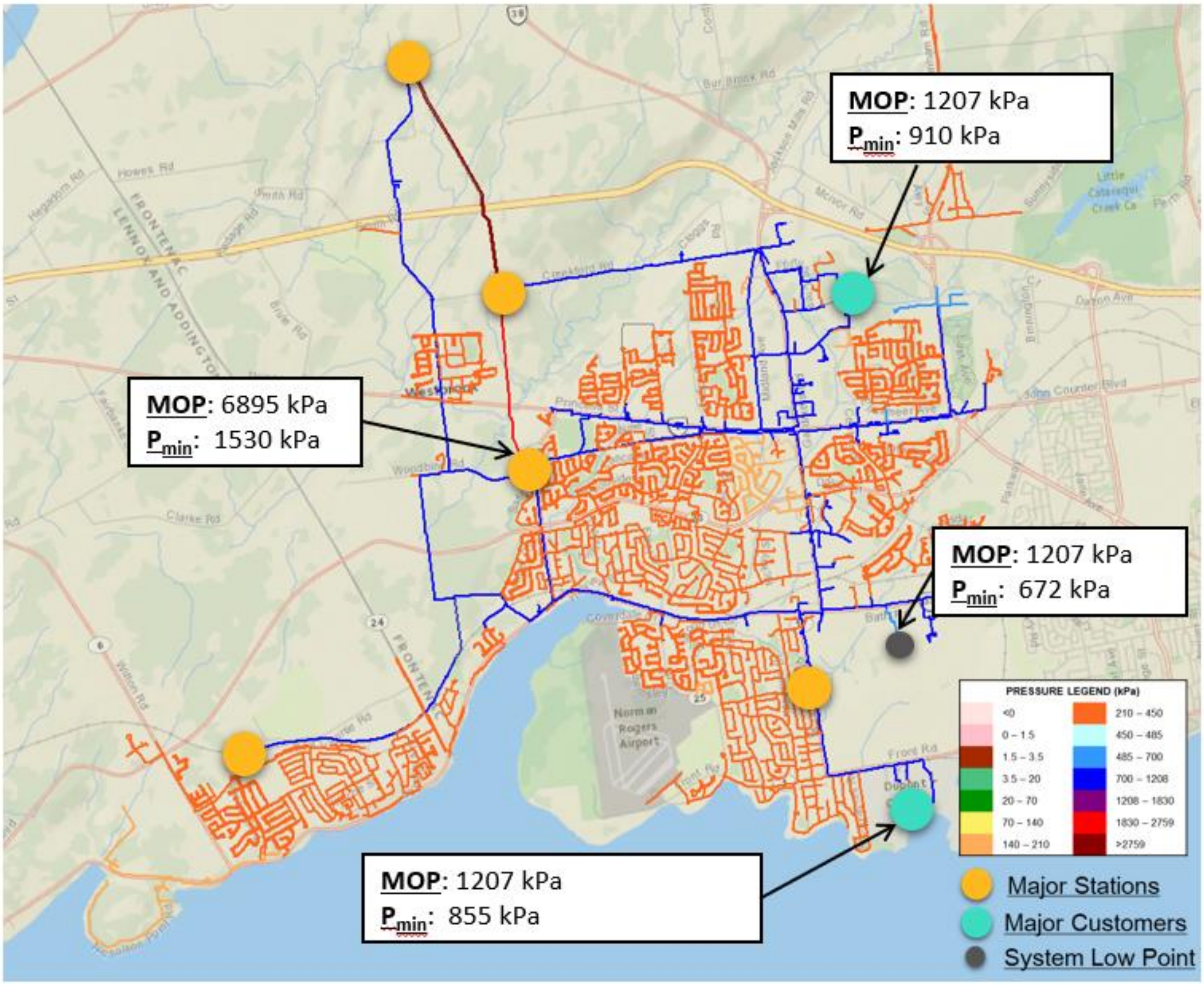
b)

Figure 3: System Map - Winter of 2022/23 after planned CNG



c)

Figure 4: System Map - Winter of 2022/23 after contract reduction



ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 1, pg. 19-20

Preamble:

EGI evidence states: *The East Kingston Creekford Rd Reinforcement project was a planned $24.3 million capital reinforcement. Enbridge Gas determined that this project could be deferred by implementing a supply side IRP alternative in the form of CNG beginning in 2022.6 Without the CNG injection, the Kingston system was anticipated to fall below its minimum pressure requirements as early as the Winter of 2022/2023. An agreement for CNG in 2022 ensured Enbridge Gas maintained a safe and reliable system for customers in the Kingston project service area. The CNG agreement was executed July 1, 2022, for the winters of 2022/2023 and 2023/2024 to ensure an in-service date of December 1, 2022. The contracted CNG service is an enabling payment to a competitive service provider, where Enbridge does not own the asset, per the IRP Decision EB-2019-0091. The 2022 charges for the CNG Agreement were approved for recovery in the IRP Operating Costs Deferral Account and the $0.278 is the 2023 cost of the CNG agreement.*

Question(s):

What was the lowest pressure recorded at the low point in the Creekford Rd. system?

a) What was the temperature at the time of the low point?

b) Did EGI seek to cancel or otherwise redeploy the CNG system after the winter of 2022/23?
   i) If not, why not?

Response:

The lowest SCADA recorded pressure at the inlet to Woodbine TBS (system low-point) in the period of January 2019 – May 2022 is ~3316 kPa, observed on June 15, 2019.

The lowest recorded winter pressure at the same location during the same time period is ~3340 kPa, observed on January 11, 2022.

a) The daily average temperatures in Kingston at the time of the low points were as follows:

- June 15, 2019: 15.1 deg C
- January 11, 2022: -17.3 deg C

b) As noted in the 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances application[1] a two-year contract agreement was signed with the CNG vendor. While Enbridge Gas sought to cancel the contract, it would have resulted in full contractual costs being incurred. There were no other needs in the area for the CNG trailers to be re-deployed to.

[1] EB-2023-0092, Exhibit C, Tab 1, p.23.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit C, Tab 1, pg. 25

Preamble:

EGI evidence states: *As previously noted, Bill 93 has resulted in increased labour rates for LSPs which has created parallel incremental costs in the Enbridge Gas VMS program since this service is performed by the same contractors. The 2021 average external contractor cost per hour was $82 and the 2023 average external contractor cost per hour was $146, a 78% increase.*

Question(s):

a) When did EGI perform the last RFP for the Locate Service Provider(s)?

b) Given the seasonality of locates (e.g. spring peak), how did EGI mitigate the costs of timely locate provision?

Response:

a) Enbridge Gas is a member of the Locate Alliance Consortium (LAC) along with 15 other Ontario utilities. LAC last had an RFP for locate services providers in 2017 but has renegotiated prices as recently as 2023.

b) Enbridge Gas mitigates seasonal locate volume variability by outsourcing locates to contractors with greater resource flexibility.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 8

Preamble:

EGI evidence states: *As detailed in Section 3.3, Enbridge Gas is also seeking OEB approval to establish a Fugitive Emissions Measurement Administration Deferral Account (FEMADA) to record administrative costs associated with the implementation of the Company's fugitive emissions investigation plan.*

We would like to understand EGI's position on recovery of costs for enhanced leak detection given increases in UFG.

Question(s):

Please explain why EGI believes that leak detection and reduction in fugitive emissions are not the responsibility of a gas utility and therefore part of the O&M budget.

Response:

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.

Enbridge Gas currently administers annual leak survey programs for its storage and transmission operations (STO) and distribution operations (DO). The existing leak survey programs, which focus on finding and repairing leaks, reflect industry standard practices and are compliant with all related regulatory requirements. As discussed in the Highwood Report,[1] the Company currently reports GHG fugitive emissions in accordance with relevant regulatory requirements using a combination of direct measurement (STO) and emission factors (DO and STO) methods.

[1] Exhibit D, Tab 1, Attachment 1, Section 7.5.1.

By design, and consistent with the commitments made as part of the 2024 Phase 1 Rebasing Settlement,[2] the proposed Investigation Plan exceeds current regulatory requirements for leak surveys and emissions reporting. Implementation of the proposed fugitive emissions Investigation Plan,[3] would involve the incremental direct measurement of leak flow rates for the distribution system, in order to improve the accuracy of the GHG fugitive emissions inventory and to help better understand its contribution to UFG. As they weren't known at the time, the costs associated with the proposed Investigation Plan were not included in any budget (O&M or otherwise) filed as part of the 2024 Phase 1 Rebasing proceeding.

For these reasons, Enbridge Gas is seeking approval to establish a Fugitive Emissions Measurement Administration Deferral Account (FEMADA), for incremental costs required to implement the proposed Investigation Plan, as agreed to as part of the 2024 Phase 1 Rebasing Settlement[4].

[2] Exhibit D, Tab 1, pp. 58-59 and EB-2022-0200 Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, Issue 1. 8(d), August 17, 2023, p. 37.
[3] As detailed at Exhibit D, Tab 1, pp. 62-63.
[4] EB-2022-0200 Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.37.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 12

Preamble:

EGI evidence states: *Importantly, nearly all comparable utility groups set out in Figure 2 also experienced a significant increase in UFG volumes in 2022. It is reasonable to assume that such trends in UFG volumes or related trends in UFG costs may be reflective of common macro- economic, geo-political, and/or national/continental weather trends, which have the potential to impact UFG volumes or costs broadly across the industry. Such trends highlight the value of comparing UFG volumes and costs experienced by a single utility to relevant peer groups over time.*

We would like to understand what is being communicated as rationale for UFG costs.

Question(s):

Please explain how UFG volumes and costs are impacted by:

a) Common macroeconomic trends
b) Geo-political trends
c) National/Continental weather trends

Response:

a) – c)

Please see the response at Exhibit I.ED-5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 15

Preamble:

EGI evidence states: *Deliveries are the volumes of gas delivered by Enbridge Gas from its integrated storage, transmission, and distribution systems to various interconnects and measured via custody transfer measurement, including:*
…..

- *Company blowdown gas (i.e., an estimate of volumes typically purged or flared for operational maintenance purposes).*

Question(s):

Please explain how EGI is estimating these blowdown gas volumes.

a) More importantly, please explain how EGI is mitigating these volumes being flared, or worse, emitted.

Response:

Blowdown gas volumes included in the determination of Sendout are the sum of individual event volumes, calculated following the methodologies prescribed by provincial and federal GHG reporting programs. The engineering calculation is as follows:

$$E = V_j\left[\frac{(273.15 + T_s)(P_{a,1} - P_{a,2})}{(273.15 + T_a)\,P_s Z_a}\right]$$

Where:

E = Natural gas venting volumetric emissions from blowdown of equipment system (Sm^3).

V_j = Total physical volume of blowdown equipment chambers (including, but not limited to, pipes, compressors, and vessels) between isolation valves for the equipment system (m^3).

T_s = Temperature at standard conditions (°C).

T_a = Temperature at actual conditions in the equipment system (°C).

P_s = Absolute pressure at standard conditions (kPa).

$P_{a,1}$ = Absolute pressure at actual conditions in the equipment system (kPa) prior to depressurization.

$P_{a,2}$ = Absolute pressure at actual conditions in the equipment system after depressurization (kPa).

Z_a = Compressibility factor for natural gas.

a) Permanent blowdown recovery units have been installed at the major Storage and Transmission Stations along the Dawn to Parkway pipeline system and are utilized to recover a portion of the gas that would have been released to atmosphere during a blowdown.

Enbridge Gas owns and operates a growing fleet of portable blowdown compressors to provide Operations with expanded capabilities for capturing blowdown gas.

Enbridge Gas also owns and operates a portable flare to combust blowdown gas that would otherwise be vented.

By using these types of equipment, Enbridge Gas reduces the amount of vented natural gas during a blowdown.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 18

Question(s):

Using the approach in Table 2, please explain how the company handles reporting, particularly for year-end, if Month 1 is December and Month 2 is January

Response:

UFG would be reported the same way as illustrated in Exhibit D, Tab 1, Table 2, if Month 1 represents December and Month 2 represents January. A billed consumption true up would occur in January when the actual meter read is available. No adjustment would be made to the UAFVA or UFGVDA to allocate the true up to the prior fiscal period for any differences between the estimated meter read and actual meter read.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 25

Preamble:

EGI evidence states: *On a monthly basis, the determination of Sendout includes an entry to record operational blowdowns or flaring associated with compressor facilities as noted in the discussion on Sendout above. By accounting for the volumes associated with these operational blowdowns or flaring, these volumes are removed from Sendout and as such do not contribute to calculated UFG volumes. A similar entry is recorded, where necessary, for blowdowns or flaring associated with capital projects.*

We are encouraged that the operational blowdowns or flaring but would like to understand how these commodity and emissions costs are accounted for.

Question(s):

Please explain where the commodity and emissions costs are allocated for:

a) Capital projects
b) Operations
c) Maintenance projects

Response:

Please see response at Exhibit I.ED-6 part d) regarding the allocation of commodity costs relating to blowdowns or flaring.

Flaring emissions associated with the compressor facilities are captured under the Ontario Emissions Performance Standard (EPS) program. As such, costs associated with the emissions are included in the Facility Carbon Charge costs, which Enbridge Gas recovers from rate classes based on in-franchise delivery volumes and ex-franchise transportation volumes.[1] These facility carbon charge costs are not capitalized. Blowdown emissions are not captured under the Ontario EPS program, and therefore there are no related emissions costs.

[1] EB-2023-0196, Exhibit D, Tab 1, Schedule 1, p.3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 26

Preamble:

EGI evidence states: *Like the accounting treatment currently applicable to the EGD Rate Zone UAFVDA, the proposed harmonized accounting order includes a provision enabling the Company to adjust for differences in estimated UFG and actual UFG to minimize timing variance(s) across fiscal years for all rate zones. The OEB accepted the Company's proposed accounting order and treatment effective January 1, 2024.*

Question(s):

What was applied to the UGL Rate Zone for 2023?

Response:

In the Union Rate Zones, consistent with the approach established for UFG Volume Variance Account (UFGVA), the adjustments associated with the difference between the estimated UFG and actual UFG made after December 2023 have been recorded in the Enbridge Gas UFGVVA for 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 29-30

Preamble:

EGI evidence states: *In 2023, the Company supported revisions to the specifications for compliance sampling used for seal extension and is currently working with Measurement Canada on pressure factor metering (PFM) specifications modernization and on specifications for ultrasonic meters*

Question(s):

Please summarize the supported revisions and the estimated costs and benefits associated with the revisions, if and when, implemented.

Response:

Compliance Sampling

For Compliance Sampling, through the Canadian Gas Association (CGA), Enbridge Gas participated in the consultation conducted by Measurement Canada (MC) from February 8, 2023, to March 8, 2023. This consultation was related to the modernization of the Weights and Measures Act and the Electricity and Gas Inspection Act, based on MC's visioning paper covering:

- Reducing barriers for business.
- Protecting consumers.
    - *Sampling* was presented to protect consumers. Industry requested clarification on this sampling, as it relates to Compliance Sampling. MC published its report named "*Summary on the consultation on the modernization of the Weights and Measures Act and the Electricity and Gas Inspection Act*" which seems to imply that this sampling will only be a monitoring tool for MC's inspectors to request information and samples of devices, and not applicable to Compliance Sampling.
- Delivering services effectively.

Compliance Sampling consultation was only to determine if the feedback from stakeholders favorably supported MC's vision to move these proposals through the legislative process, and ultimately to Parliament for consideration. Due to the nature of the legislative process and its current status (not a bill of parliament yet), it is premature to quantify any costs or benefits associated with these activities at this time.

Pressure Factor Metering

A CGA joint working group was assembled to propose changes to MC's PFM specifications (PS-G-17). The preferred proposal covers:

- Expanding the scope to include multiple meter PFMs.
- Permitting alternative approaches for installation of pressure taps on multiple meter PFMs, updating requirements for regulator marking, and installation records.

Given that MC has not yet taken any action on the proposed changes it is premature to quantify any costs or benefits associated with these activities at this time.

Specifications for Ultrasonic Meters

Industry/CGA provided the essential information for MC to initiate a review of specifications and legislation themselves. This is aimed at modernizing PS-G-06 - Provisional specifications for the approval, verification, reverification, installation and use of ultrasonic meters.

This work is in the early stages and has not advanced yet due to re-organization issues at MC and the 2024 change in approach from MC on how the Gas Process Advisory Committee (GPAC) will function. Therefore, it is premature to quantify any costs or benefits associated with these activities at this time.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 34-35 and Table 5

Preamble:

We would like to understand the issue of Historical Vacant Premises Lockouts, what has been found and the impact on the historic lost.

Question(s):

Please extend Table 5 to show the number from each year were resolved and the amount of gas that was "found" and any recoveries from the building owner.

a) How were the gas costs associated with the found gas allocated?

Response:

A vacant premise is resolved when there is a subsequent meter unlock and customer move-in. The volumes associated with that premise is resolved by backdating the consumption as part of the normal billing process making it difficult to accurately go back and quantify how much volume is attributable to the period during which the premises was vacant.

The volume of gas "found", and corresponding costs (recoveries) associated with the resolution of vacant premises lockouts is difficult to quantify as it would require that Enbridge Gas query customer consumption data for each premises and conduct unique investigations into account-specific activity. As conducting such a task would be onerous, Enbridge Gas respectfully declines to provide these figures.

Table 1 includes the number of resolved vacant premises compared to the number of vacant premises lockouts annually.

Table 1

Historical Vacant Premises Lockouts

Line No.	Year	No. of Vacant Premises Lockouts	No. of Resolved Vacant Premises Lockouts
1	2018	3,504	3,343
2	2019	9,465	9,112
3	2020	809	742
4	2021	7	6
5	2022	813	754
6	2023	3,589	3,294

a) Please see the response at Exhibit.I.CCC-4 part a) for discussion of how vacant premises gas costs are allocated.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 38

Preamble:

EGI evidence states: *As noted in its 2024 Phase 1 Rebasing application,40 Enbridge Gas is committed to Advanced Metering Infrastructure (AMI) and advised that it plans to file a stand-alone AMI application as soon as practicable that will request approval from the OEB for funding and to implement an AMI solution.*

Question(s):

Please provide EGI's most recent assessment of the cost and benefits of an AMI system in the EGI franchise.

a) If not available, please provide a recent cost/benefit analysis that has been published for a gas-only utility in North America.

Response:

Enbridge Gas is currently finalizing its cost/benefit review and expects to provide a detailed economic feasibility analysis as part of a future comprehensive AMI application to the OEB. This analysis will reflect the Company's unique operations, ensuring an accurate evaluation.

a) Enbridge Gas does not have any recent cost-benefit analyses of AMI for gas-only natural gas utilities in North America.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 40

Preamble:

EGI evidence states: *For communities that fall within more than one elevation zone (with an elevation difference exceeding 110 m between maximum/minimum elevations), unique elevation factors (e.g., air pressure, barometric pressure area) may need to be established in the Company's billing systems to adjust for the effect of atmospheric pressure on volumes of natural gas delivered.*

Question(s):

Please confirm that these Measurement Canada standards have been in place for decades.

a) Please describe the UGL and EGD compliance with these requirements and provide the year of implementation of the standards.

b) Please explain what has changed such that impacts of elevation difference would be resulting in unaccounted for gas.

Response:

Confirmed. The Measurement Canada (MC) standards are established in the Electricity and Gas Inspection Regulations and have been in place since 1986.

a) Since MC's standards were put in place, Union and EGD implemented processes to establish elevation zones that cover all land elevations within the franchise areas. The defined maximum and minimum elevation for each elevation zone represents a difference of 110 m which is consistent with tolerances established in the referenced Regulations. An elevation-based atmospheric pressure is calculated for each elevation zone in accordance with the referenced Regulations. Following an elevation survey, a defined geographic area within the franchise is assigned to an established elevation zone. The calculated atmospheric pressure associated with the elevation zone is used for all meter locations within the defined geographic area. This ensures compliance with the referenced Regulations.

b) Enbridge Gas recognizes that communities having a range of elevations exceeding 110 m need to be divided between differing elevation zones. Assigning such communities to a single elevation zone can result in the application of an incorrect pressure elevation factor to some accounts and a potential increase or decrease in UFG depending on the specific circumstances.

   The Company is simply investigating to ensure that pre-established pressure elevation factors are consistent with Measurement Canada standards and accurately reflect elevation zones.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 42

Preamble:

EGI evidence states: *Given the magnitude of natural gas volumes consumed by General Service customers, the Company expects that replacement of manual meter reading with an automated and remote process for those customers could significantly reduce incidence of billing based on estimated Consumption and related UFG volumes.*

In past proceedings, EGI has stated that billing problems did not impact UFG. The above reference seems to suggest it does.

Question(s):

Please explain how billing based on estimated consumption could contribute to UFG.

a) Please provide the amounts quantified for each UGL and EGD Rate Zones for each year of 2021, 2022 and 2023.

Response:

Billing based on estimated volumes does not contribute to incremental UFG. However, it could contribute to increased UFG volatility in the short-term as previously stated in the Unaccounted for Gas Progress Report.[1]

As shown at Exhibit D, Tab 1, Section 1.3, Table 2, to the extent that estimated consumption billed varies from actual consumption in a month, UFG will be “created”. Once a meter is read, the estimated consumption is replaced with an actual measured consumption for the period since the previous meter read. The customer is then billed at the appropriate QRAM rate for all unbilled volumes remaining on the account and the UFG is “trued-up”.

[1] EB-2021-0148, Exhibit C, Tab 2, Schedule 1, p.18.

While this “creation” and “true up” of UFG does not result in UFG volumes in the long-term, any such billing adjustments which are applied in the current fiscal year for a month already billed in a previous year will have the impact of creating volatility in reported annual UFG volume numbers.

The replacement of manual meter reading with an automated and remote process would significantly reduce incidences of billing based on estimated consumption which would resolve the aforementioned UFG volume volatility.

Please see the response at Exhibit I.FRPO.20 for discussion on the current impacts of point in time reporting of UFG on UFG volatility.

a) Please see the response at Exhibit I.STAFF-7 part d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 47 and Table 8

Preamble:

EGI evidence states: *Said differently, to the extent that a variance existed between estimated Consumption and actual Consumption for the Union Rate Zones, any adjustment(s) made after December have historically been recorded in the subsequent fiscal year. As a result, unbilled estimate-related UFG volumes for the Union Rate Zones increased UFG volumes in 2022 and subsequently suppressed UFG volumes in 2023*

Question(s):

Please describe the impacts of these adjustments and any impact on ratepayers given the deadband.

Response:

The figures set out in Table 8 reflect the benefit of having an additional year of billing adjustments which would not be the case at the time that Enbridge Gas calculated UFG volumes for 2022 (January 2023). As noted in evidence,[1] the historic OEB-approved operation of the Union Rate Zones UFGVDA does not include recording adjustments across fiscal years, and this was only changed upon harmonization of related accounts effective January 2024. Further, it is not appropriate to consider No Bills impacts in isolation as they can be offset by unbilled estimates. Please see the response at Exhibit I.STAFF.7 part d), for discussion of the net impact of each of these contributing sources to annual UFG volumes over multiple years.

Enbridge Gas respectfully declines to provide the information requested given the Union Rates Zones UFGVDA does not operate in the hypothetical manner suggested by FRPO.

[1] Exhibit D, Tab 1, p.26.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 52-57 and Table 9 and 10

Preamble:

EGI evidence states: *Distribution pipeline system station pressures are typically held constant year-round and demands reduce over the length of each segment.*

Question(s):

Please explain the changes in minimum linepack in the EGD system from 2022 to 2023, especially for distribution given the above reference.

a) Did the reduction in linepack provide more gas into Sendout thus increasing UFG? Please explain fully.

Response:

The reduction in Distribution linepack detailed in Table 9,[1] from 2022 (8,317 10^3m^3) to 2023 (6,780 10^3m^3) is primarily attributable to incorrect accounting for a large diameter distribution pipeline in the EGD Rate Zone beginning in 2021 (1,651 10^3m^3). This was subsequently corrected in 2023. Aside from this correction, minor annual updates to inputs across distribution models also contributed to the variance between 2022 and 2023 (both positively and negatively). The net variance between 2022 and 2023 was 1,537 10^3m^3.

a) The effect of the error recognized in Distribution Linepack discussed above was twofold:
   i. to decrease UFG in 2021 by 1,651 10^3m^3, when it was incorrectly added to distribution models, and
   ii. to increase UFG in 2023 by 1,651 10^3m^3, when it was corrected by removing it from distribution models.

[1] Exhibit D, Tab 1, Table 9, p.52.

UFG volumes in 2022 were not specifically affected by these adjustments. For further explanation, please see the response at Exhibit I.STAFF-7 part d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 52-57 and Table 9 and 10

Preamble:

EGI evidence states: *Distribution pipeline system station pressures are typically held constant year-round and demands reduce over the length of each segment.*

Question(s):

Has EGI assessed reducing distribution pressures in the non-heating seasons as a means of reducing fugitive emissions?

i) If so, please explain
ii) If not, why not?

Response:

No, Enbridge Gas has not assessed the impact of reducing distribution pressures in the non-heating season to reducing fugitive emissions as there are unacceptable safety and reliability concerns associated with such operational decisions, including but not limited to:

- Operating pressures of pipeline systems are determined to ensure uninterrupted supply of natural gas to customers at any time of year. Any unexpected temperature drops could result in an inability for Enbridge Gas to react quickly enough to avoid impacting its customers.

- Not all Enbridge Gas customer consumption is weather dependent. Many of the referenced distribution pipelines serve industry which require natural gas on a different schedule (process load).

- The Company's pipeline systems are interconnected, and some pipelines have multiple stations feeding into them which all need to remain balanced; in such circumstances it is not physically possible to operate one station at a lower pressure while maintaining other connected stations at higher pressures.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 52-57 and Table 9 and 10

Preamble:

EGI evidence states: *Distribution pipeline system station pressures are typically held constant year-round and demands reduce over the length of each segment.*

Question(s):

Please provide Table 10 values for December 2023 and January 2024.

a) Please describe and quantify the impact on 2023 year-end.

Response:

As requested, values for December 2023 and January 2024 have been added in Table 1.[1]

[1] Values for December 2023 and January 2024 were added to the original table presented in pre-filed evidence at Exhibit D, Tab 1, Table 10, p. 55.

Table 1
Updated Dawn-Parkway Operational Linepack Adjustments

Line No.	Particulars (10^3m^3)	Aug 2022	Sep 2022	Oct 2023	Nov 2023	Dec 2023	Jan 2024
		(a)	(b)	(a)	(b)	(a)	(b)
1	Absolute Activity	4,075,901	3,321,413	2,529,696	4,721,557	5,208,835	6,872,645
2	Total Receipts	2,386,408	1,977,352	1,669,918	2,946,788	3,223,555	4,208,749
3	Total Deliveries	1,689,492	1,344,061	859,779	1,774,769	1,985,280	2,663,896
4	Dawn Parkway System Linepack Receipts	2,093	-	2,069	-	-	-
5	Dawn Parkway System Linepack Deliveries	-	3,427	-	1,404	82	477
6	Dawn Parkway System Linepack Adjustment *(% of absolute activity)*	0.05%	0.10%	0.08%	0.03%	0.00%	0.01%

NOTES:

- An error has been corrected for the October 2023 Linepack Receipt value in line 4 of Table 1.

a) At 2023 year-end, the impact to Operational Linepack of delivery in December (set out in Table 1 row 5) was an increase to UFG volumes for the fiscal year 2023 of approximately 82 10^3m^3 (i.e., 0.0016% of throughput).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 61 and Table 11

Question(s):

Please provide a breakdown of the components that contribute to such a high vehicle cost.

Response:

The following response was provided by Highwood Emissions Management:

The estimated vehicle costs in Table 11, which are based on the costs provided in the Highwood Report (please see 2024-05-31, EB-2024-0125, Exhibit D, Tab 1, Attachment 1, p.76, Table 24), are for annual system coverage of EGI's Distribution Operations (DO). These costs include a capital component associated with purchasing mobile analyzer units and an annual component for service expenses over a five-year term. These costs were obtained based on confidential vendor quotes and scaled up for Enbridge's distribution system, which includes over 140,000 km of mains and service pipelines. The costs estimated by Highwood did not include operational costs for ground follow-up to classify and repair leaks found as part of mobile surveys, which may be significant based on the number of leaks found. High vehicle costs for full system coverage of a utility distribution network are not unexpected due to the vast nature of the pipeline network, limitations due to external factors such as speed limits in urban areas and seasonality, and the number of sensors/vehicles that would be required.

Typical components which go into vehicle based monitoring may include:

- Onboard gas intake and gas analyzers
- GPS tracking system
- Anemometer to record wind speed and direction
- Communication device to access cloud data storage
- Proprietary analytics for emissions quantification

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 61

Preamble:

EGI evidence states: *STO fugitive emissions are already being measured and quantified three times per year.*

Question(s):

How are the measurements determined and quantified.

a) Please provide the last 3 years of measurement for STO fugitive emissions.

b) Please provide the measurements disaggregated by storage and transmission.

Response:

As discussed at Exhibit D, Tab 1, Attachment 1, page 57, compressor stations and storage and meter/receipt stations are surveyed three times per year, in compliance with the federal methane regulation, by foot patrol using Optical Gas Imaging (OGI) to detect leaks. Hi-flow samplers are then used to quantify leak flow rates. Fugitive emissions from compressor stations and meter/receipt stations are calculated using the measured flow rates from the regulatory LDAR surveys. The annual leak volume for a given reporting year is estimated by taking the measured leak flow rates from the surveys and approximating the leak duration in accordance with the provincial GHG reporting program.

a) Please see response at Exhibit.I.MC-9 part b).

b) A breakdown by compressor station is provided at Exhibit.I.MC-9 part b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit D, Tab 1, pg. 66

Preamble:

EGI evidence states: *To support implementation of the Fugitive Emissions Investigation Plan, Enbridge Gas is seeking OEB approval to establish a Fugitive Emissions Measurement Administration Deferral Account (FEMADA) to record the incremental administration costs, inclusive of Pilot costs, incurred to implement the plan.*

Question(s):

Please provide the principled basis and other justification for considering reducing fugitive emissions outside of the scope of normal utility operations to operate a safe, secure delivery system.

Response:

Please see the response at Exhibit I.FPRO-17.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, pg. 8-11

Question(s):

Please provide the total amount of Short-term storage sold disaggregated between peak and non-peak storage.

a) Please provide the provide the monthly pricing, gross revenue by month and the costs identified by their source to arrive at net revenue.

Response:

Total short-term peak storage sales amounted to 3.2 PJ (1.9 PJ Utility and 1.4 PJ non-utility).[1] Total short-term off-peak storage sales amounted to 4.9 PJ.

a) Enbridge Gas does not structure market-based storage contracts using monthly demand charges. Rates for short-term market-based storage services are typically negotiated as a single demand charge. That demand charge is recovered in monthly installments over the term of the contract. Any applicable cycling fees are recovered in the month incurred.

   Please see Exhibit E, Tab 1, Schedule 2 for a breakdown of 2023 annual gross short term storage revenue by service and cost by source. Please see Table 1, for monthly revenue detail. Costs are allocated on an annual basis.

[1] As detailed in Exhibit E, Tab 1, Schedule 4.

Table 1

Monthly Gross Short-Term Storage Revenue by Service

Line No.	Particulars ($000's)	C1 Peak Storage	C1 Off-Peak Storage	Other	Total
1	January	219.8	0.7	37.6	258.1
2	February	202.9	(0.4)	59.9	262.4
3	March	327.3	113.7	45.5	486.5
4	April	494.1	154.5	59.0	707.6
5	May	495.8	153.9	90.1	739.7
6	June	400.2	149.6	33.5	583.3
7	July	(672.0)	148.8	75.2	(448.0)
8	August	230.4	152.0	104.1	486.5
9	September	231.1	173.3	77.6	481.9
10	October	234.3	0.0	58.6	292.8
11	November	236.7	-	211.6	448.4
12	December	233.1	-	51.1	284.2
13	Total	2,634	1,046	904	4,583

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario (FRPO)

Interrogatory

Reference:

Exhibit E, Tab 1, pg. 13-18 and Tables 1-3 and Schedule 5

Question(s):

Please provide in Excel format with accompanying description, how the 2023 Target and Actual NAC's for M1 and M2 in Tables 1 and 2 are determined.

a) Please provide in Excel format the monthly data and determination of the values in Schedule 5.

b) For 2023 calculations, please provide and describe the selection of the months used for the determination of storage amounts (from 2022, 2023 or 2024)

Response:

a) Please see Attachment 1 for the monthly data and determination of the values in Schedule 5 in Excel format.

b) The calculation for the annual Storage Cost Balance is determined based on the gas year (April to March) but has been calendarized over the 12-months for presentation purposes in Attachment 1. Please see Exhibit E, Tab 1, Section 4, pages 16 - 18 for a description of the storage cost calculation.

Table 1
Union Rate Zones
Calculation of Balances by Rate Class in the NAC Deferral Account (No. 179-133) - Base Rates and Y-Factor

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Net Account Balance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	BASE RATES														
	2023 Target NAC (m^3)														
1	Rate M1	453	399	349	210	122	80	64	65	69	159	257	404	2,630.8	
2	Rate M2	22,283	21,780	19,271	11,806	8,300	5,671	2,543	5,219	5,947	12,071	13,903	19,348	148,142.6	
3	Rate 01	503	406	369	228	138	73	41	53	64	173	270	414	2,730.6	
4	Rate 10	23,995	23,623	15,679	12,935	8,661	4,275	2,884	4,150	6,584	12,255	13,995	20,673	149,709.1	
	2023 Actual NAC (m^3)														
5	Rate M1	414	470	352	231	123	64	71	66	76	132	291	390	2,680.5	
6	Rate M2	13,177	32,077	19,364	10,374	8,976	4,624	4,672	5,030	5,555	9,960	15,964	19,576	149,348.5	
7	Rate 01	452	455	366	224	124	57	45	60	61	153	300	414	2,709.1	
8	Rate 10	13,178	27,029	17,922	10,125	9,071	4,113	3,878	4,366	5,640	10,539	15,852	19,224	140,937.4	
	Actual Change in NAC (m^3)														
9	Rate M1	38	(70)	(3)	(20)	(1)	16	(7)	(1)	(7)	27	(35)	14	(49.7)	
10	Rate M2	9,107	(10,297)	(93)	1,432	(676)	1,047	(2,129)	189	392	2,111	(2,061)	(228)	(1,206.0)	
11	Rate 01	51	(49)	4	5	14	16	(4)	(7)	3	20	(30)	(0)	21.5	
12	Rate 10	10,817	(3,406)	(2,242)	2,810	(411)	162	(994)	(216)	945	1,715	(1,857)	1,449	8,771.7	
	Y-FACTOR														
	2023 Target NAC (m^3)														
13	Rate M1	461	403	346	214	118	66	63	60	65	132	259	385	2,572.3	
14	Rate M2	22,827	22,417	19,803	13,404	8,233	5,015	4,788	5,063	6,136	11,338	16,569	20,782	156,374.8	
15	Rate 01	516	420	365	231	128	66	56	55	68	154	294	411	2,763.3	
16	Rate 10	25,218	23,962	19,857	13,038	8,810	5,218	5,181	4,715	6,569	11,651	16,422	22,406	163,046.7	
	2023 Actual NAC (m^3)														
17	Rate M1	414	470	352	231	123	64	71	66	76	132	291	390	2,680.5	
18	Rate M2	13,177	32,077	19,364	10,374	8,976	4,624	4,672	5,030	5,555	9,960	15,964	19,576	149,348.5	
19	Rate 01	452	455	366	224	124	57	45	60	61	153	300	414	2,709.1	
20	Rate 10	13,178	27,029	17,922	10,125	9,071	4,113	3,878	4,366	5,640	10,539	15,852	19,224	140,937.4	
	Actual Change in NAC (m^3)														
21	Rate M1	47	(67)	(7)	(16)	(5)	2	(7)	(6)	(11)	(0)	(32)	(5)	(108.2)	
22	Rate M2	9,650	(9,660)	439	3,030	(743)	391	117	33	581	1,378	606	1,206	7,026.3	
23	Rate 01	64	(35)	(1)	7	4	9	11	(5)	7	1	(6)	(3)	54.2	
24	Rate 10	12,040	(3,067)	1,935	2,913	(261)	1,106	1,303	349	929	1,111	570	3,182	22,109.3	

Table 1 (Continued)
Union Rate Zones
Calculation of Balances by Rate Class in the NAC Deferral Account (No. 179-133) - Base Rates and Y-Factor (Continued)

Line No.	Particulars		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Net Account Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	2013 Board-approved number of Customers															
25	Rate M1		1,052,461	1,053,700	1,055,215	1,056,446	1,058,261	1,057,701	1,059,313	1,059,545	1,060,791	1,061,354	1,064,258	1,067,757.0		
26	Rate M2		6,724	6,820	6,823	6,810	6,818	6,948	6,834	6,646	6,760	6,742	6,748	6,778.0		
27	Rate 01		318,095	318,403	318,627	318,931	319,292	319,442	320,050	320,011	320,308	321,025	322,261	323,287.0		
28	Rate 10		2,042	2,047	2,048	2,048	2,048	2,051	2,053	2,055	2,055	2,059	2,059	2,064.0		1,399,886.0
	BASE RATES															
	Volume impact (10^3 m^3)	(1)														
29	Rate M1		40,145	(74,209)	(3,389)	(21,347)	(819)	16,554	(7,153)	(1,092)	(7,650)	28,578	(36,863)	14,744	(52,502)	
30	Rate M2		61,233	(70,224)	(636)	9,750	(4,611)	7,273	(14,550)	1,258	2,652	14,231	(13,906)	(1,542)	(9,071)	
31	Rate 01		16,071	(15,664)	1,120	1,437	4,473	5,188	(1,310)	(2,192)	974	6,339	(9,577)	(62)	6,797	
32	Rate 10		22,088	(6,972)	(4,592)	5,755	(841)	332	(2,041)	(445)	1,941	3,532	(3,823)	2,991	17,925	(36,851)
	2023 Net Annual Delivery Rate ($/$m^3$)	(2)														
33	Rate M1		$0.044	$0.044	$0.044	$0.042	$0.042	$0.042	$0.042	$0.042	$0.042	$0.042	$0.042	$0.042	$0.043	
34	Rate M2		$0.042	$0.042	$0.042	$0.041	$0.041	$0.041	$0.040	$0.040	$0.040	$0.041	$0.041	$0.041	$0.042	
35	Rate 01		$0.102	$0.102	$0.102	$0.099	$0.099	$0.099	$0.099	$0.099	$0.099	$0.099	$0.099	$0.099	$0.100	
36	Rate 10		$0.067	$0.067	$0.067	$0.064	$0.064	$0.064	$0.064	$0.064	$0.064	$0.064	$0.064	$0.064	$0.066	
	2023 Net Annual Average Storage Rate ($/$m^3$)	(3)														
37	Rate M1		$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	
38	Rate M2		$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	
39	Rate 01		$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	$0.050	
40	Rate 10		$0.039	$0.039	$0.039	$0.039	$0.039	$0.039	$0.039	$0.039	$0.039	$0.039	$0.039	$0.039	$0.039	
	Delivery Rate ($000)	(4)														
41	Rate M1		$1,768	($3,269)	($149)	($901)	($35)	$698	($300)	($46)	($321)	$1,206	($1,556)	$622	($2,280)	
42	Rate M2		$2,589	($2,969)	($27)	$395	($187)	$295	($586)	$51	$107	$577	($564)	($63)	($382)	
43	Rate 01		$1,645	($1,604)	$115	$142	$443	$514	($129)	($216)	$96	$629	($950)	($6)	$680	
44	Rate 10		$1,476	($466)	($307)	$369	($54)	$21	($130)	($28)	$124	$226	($245)	$192	$1,178	($805)
	Storage Rate ($000)	(4)														
45	Rate M1		$362	($670)	($31)	($193)	($7)	$149	($65)	($10)	($69)	$258	($333)	$133	($474)	
46	Rate M2		$521	($598)	($5)	$83	($39)	$62	($124)	$11	$23	$121	($118)	($13)	($77)	
47	Rate 01		$807	($787)	$56	$72	$223	$259	($65)	($109)	$49	$316	($478)	($3)	$340	
48	Rate 10		$868	($274)	($180)	$224	($33)	$13	($79)	($17)	$76	$138	($149)	$117	$702	$491

Table 1 (Continued)
Union Rate Zones
Calculation of Balances by Rate Class in the NAC Deferral Account (No. 179-133) - Base Rates and Y-Factor (Continued)

Line No.	Particulars		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Net Account Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Y-FACTOR															
	Volume impact (10^3 m^3)	(1)														
49	Rate M1		49,103	(70,250)	(7,147)	(17,234)	(5,209)	1,924	(7,721)	(6,431)	(11,805)	(68)	(34,113)	(5,718)	(114,669)	
50	Rate M2		64,887	(65,882)	2,995	20,637	(5,069)	2,716	797	219	3,927	9,289	4,087	8,171	46,775	
51	Rate 01		20,230	(11,041)	(179)	2,288	1,353	3,009	3,438	(1,510)	2,173	240	(1,854)	(889)	17,258	
52	Rate 10		24,586	(6,279)	3,963	5,965	(535)	2,268	2,675	718	1,909	2,288	1,174	6,567	45,299	(5,337)
	2023 Net Annual Delivery Rate ($/$m^3$)	(2)														
53	Rate M1		$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	
54	Rate M2		$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	$0.014	
55	Rate 01		$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	$0.006	
56	Rate 10		$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	$0.009	
	2023 Net Annual Average Storage Rate ($/$m^3$)	(3)														
57	Rate M1		$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	
58	Rate M2		$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	
59	Rate 01		$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	
60	Rate 10		$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	
	Delivery Rate ($000)	(4)														
61	Rate M1		$680	($973)	($99)	($239)	($72)	$27	($107)	($89)	($164)	($1)	($473)	($79)	($1,588)	
62	Rate M2		$878	($891)	$41	$279	($69)	$37	$11	$3	$53	$126	$55	$111	$633	
63	Rate 01		$120	($66)	($1)	$14	$8	$18	$20	($9)	$13	$1	($11)	($5)	$103	
64	Rate 10		$224	($57)	$36	$54	($5)	$21	$24	$7	$17	$21	$11	$60	$412	($441)
	Storage Rate ($000)	(4)														
65	Rate M1		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
66	Rate M2		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
67	Rate 01		$0	($0)	($0)	$0	$0	$0	$0	($0)	$0	$0	($0)	($0)	$0	
68	Rate 10		$0	($0)	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$1	$1

Table 1 (Continued)
Union Rate Zones
Calculation of Balances by Rate Class in the NAC Deferral Account (No. 179-133) - Base Rates and Y-Factor (Continued)

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Net Account Balance
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Total Balance Amounts ($000)														
	Total Delivery Balance ($000)														
69	Rate M1	$2,449	($4,242)	($248)	($1,139)	($107)	$725	($407)	($135)	($484)	$1,205	($2,028)	$543	($3,869)	
70	Rate M2	$3,467	($3,860)	$14	$675	($256)	$332	($575)	$54	$160	$703	($509)	$48	$251	
71	Rate 01	$1,766	($1,669)	$114	$156	$451	$532	($109)	($225)	$109	$630	($961)	($11)	$783	
72	Rate 10	$1,700	($523)	($271)	$423	($59)	$42	($106)	($22)	$141	$247	($234)	$251	$1,590	($1,245.5)
	Total Storage Balance ($000)														
73	Rate M1	$362	($670)	($31)	($193)	($7)	$149	($65)	($10)	($69)	$258	($333)	$133	($474)	
74	Rate M2	$521	($598)	($5)	$83	($39)	$62	($124)	$11	$23	$121	($118)	($13)	($77)	
75	Rate 01	$808	($787)	$56	$72	$223	$259	($65)	($109)	$49	$316	($478)	($3)	$340	
76	Rate 10	$868	($274)	($180)	$224	($33)	$13	($79)	($17)	$76	$138	($149)	$117	$703	$491.6
	Storage Costs ($000) (2) (5)														
77	Rate M1	($89)	($89)	($89)	($89)	($89)	($89)	($89)	($89)	($89)	($89)	($89)	($89)	($1,065)	
78	Rate M2	($102)	($102)	($102)	($102)	($102)	($102)	($102)	($102)	($102)	($102)	($102)	($102)	($1,226)	
79	Rate 01	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($35)	($420)	
80	Rate 10	($16)	($16)	($16)	($16)	($16)	($16)	($16)	($16)	($16)	($16)	($16)	($16)	($186)	($2,897)
	2023 Interest ($000) (6)														
81	Rate M1	$0	$70	($4)	($8)	($6)	($5)	($1)	($10)	($13)	($14)	$10	($22)	($1)	
82	Rate M2	$0	$14	($1)	($1)	($1)	($1)	($0)	($2)	($2)	($3)	$2	($4)	($0)	
83	Rate 01	$0	($9)	$1	$1	$1	$1	$0	$1	$2	$2	($1)	$3	$0	
84	Rate 10	$0	($27)	$2	$3	$2	$2	$0	$4	$5	$5	($4)	$9	$0	($0.8)
	Total Deferral Account Amounts ($000)														
85	Rate M1	$2,722	($4,931)	($372)	($1,428)	($209)	$781	($561)	($243)	($655)	$1,360	($2,439)	$565	($5,409)	
86	Rate M2	$3,886	($4,547)	($95)	$654	($398)	$290	($802)	($40)	$78	$719	($727)	($72)	($1,051.9)	
87	Rate 01	$2,538	($2,500)	$135	$194	$640	$757	($209)	($368)	$124	$913	($1,475)	($47)	$703	
88	Rate 10	$2,553	($840)	($465)	$635	($105)	$41	($200)	($51)	$206	$375	($403)	$361	$2,106	($3,651.6)
	2024 Interest ($000) (6)														
81	Rate M1	($25)	$2	$23	($33)	($33)	($33)	($33)	($33)	($33)	($33)	($33)	($33)	($297)	
82	Rate M2	($5)	$0	$5	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($58)	
83	Rate 01	$3	($0)	($3)	$4	$4	$4	$4	$4	$4	$4	$4	$4	$39	
84	Rate 10	$10	($1)	($9)	$13	$13	$13	$13	$13	$13	$13	$13	$13	$116	($200)
	Final Total Deferral Account Amounts ($000)														
85	Rate M1	$2,697	($4,929)	($348)	($1,461)	($242)	$748	($594)	($276)	($688)	$1,327	($2,472)	$532	($5,706)	
86	Rate M2	$3,881	($4,546)	($90)	$647	($404)	$284	($808)	($46)	$72	$713	($734)	($78)	($1,110)	
87	Rate 01	$2,542	($2,501)	$132	$198	$645	$761	($205)	($364)	$129	$917	($1,471)	($42)	$741	
88	Rate 10	$2,562	($841)	($474)	$647	($92)	$54	($187)	($38)	$219	$388	($390)	$374	$2,222	($3,852.1)

Notes:
(1) The annual volume is obtained from a monthly calculation of approved customers and the monthly usage variance.
(2) The Net Annual Average Delivery Rate is the volume-weighted average of Board-approved monthly unit rates in effect
(3) The Net Annual Average Storage Rate is the volume-weighted average of Board-approved monthly unit rates in effect
(4) The annual revenue is obtained from a monthly calculation of volumes and the monthly unit delivery and storage rates.
(5) Storage costs are determined based on a gas year (April-March). The costs have been presented on a calendar year basis
(6) Interest is calculated on the monthly opening balance in the deferral account in accordance with the methodology approved by the Board in EB-2006-0117. Interest is calculated to Dec 31st, 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Kitchener Utilities (Kitchener)

Interrogatory

Reference:

Exhibit E Tab 1 Schedule 2 Appendix A Page 1 of 1, line 16

Question(s):

Please explain and provide the formulas and sample calculation of storage deliverability for T3 rate shown in the table?

Response:

The total Union South Rate Zone storage deliverability of 1,840,855 GJ/d, shown at line 17, column (b) of Exhibit E, Tab 1, Schedule 2, Appendix A represents the total Union South Rate Zone storage deliverability based on forecast W23/24 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 Board-approved cost allocation methodologies for the allocation of storage deliverability related costs. Please see Attachment 1.

Table 1
Allocation of Union South Rate Zone Storage Deliverability

Line No.	Particulars	Storage Deliverability Allocation Factor (1) (10^3m^3/day)	(%)	Allocation of W23/24 Forecast Storage Deliverability (2)
		(a)	(b)	(c)
	Union South Rate Zone			
1	Rate M1	22,551	52.9%	973,899
2	Rate M2	7,237	17.0%	312,539
3	Rate M4	3,964	9.3%	171,205
4	Rate M5	7	0.0%	286
5	Rate M7	1,529	3.6%	66,050
6	Rate M9	215	0.5%	9,286
7	Rate M10	3	0.0%	142
8	Rate T1	932	2.2%	40,244
9	Rate T2	4,573	10.7%	197,492
10	Rate T3	1,614	3.8%	69,712
11	Total Union South Rate Zone	42,627	100.0%	1,840,855

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
Minogi Corp. (MC)

Interrogatory

Reference:

• Exhibit D, Tab 1, p. 10
• Exhibit D, Tab 1, pp. 29-44, 58-66
• Exhibit D, Tab 1, Attachment 1, “EGI Fugitive Emissions Measurement Report” (the “Highwood Report”)

Preamble:

EGI states that total system unaccounted-for gas (“UFG”) in 2023 amounted to approximately 201,845 103m3 (79,232 103m3 in the EGD Rate Zone and 122,613 103m3 in the Union Rate Zones) compared to total system throughput for that same year of approximately 56,645,986 103m3 (0.36%).

EGI notes that fugitive emissions were understood to mean the unintended release of natural gas due to leaks or third-party damages. They do not include emissions from venting, combustion, or flaring.

Question(s):

a) Please provide details on the sample area selected by EGI for measuring fugitive emissions.

b) Please discuss all testing, monitoring, and measurements of UFGs that has occurred or will occur as a result of the application on First Nations reserves that are serviced by EGI. If no such testing, monitoring, and/or measurements have occurred or are expected to occur, please explain why not.

c) How can EGI be confident that the sample areas it has selected are (or are not) reflective of the emissions and relevant circumstances of First Nations reserves that are serviced by EGI?

d) Please describe and discuss all initiatives EGI is developing, has or is in the process of implementing to reduce UFG. In your response, please discuss the expected reduction in fugitive emissions from such initiatives.

e) Please discuss the applicability of all such initiatives to emissions taking place on First Nations reserves serviced by EGI, as well as any analysis that EGI has conducted towards reaching those conclusions.

f) Please discuss all initiatives EGI has identified and is evaluating to reduce UFG.

g) What is EGI's main source of fugitive emissions?

h) Is EGI required to report its UFG in their GHG emissions reporting?

<u>Response:</u>

a) and c)

A sample area has not yet been selected. Enbridge Gas will develop a detailed plan following receipt of related OEB approvals sought in the current proceeding (i.e., to establish the proposed FEMADA). Please see the response at Exhibit I.ED-12, for additional discussion regarding the approvals sought and estimated timelines for the proposed Fugitive Emissions Investigation Plan discussed in Exhibit D, Tab 1, paragraph 122. Enbridge Gas will continue to engage with Indigenous groups through the IWG and other mechanisms, to seek feedback on the implementation of the FEMP project.

b) and e)

As discussed in the response at Exhibit I.ED-9 part b), UFG is the difference between the measured gas volumes delivered into the system (defined as net gas sendout or Sendout volumes for the purposes of the current Application)[1] and the measured gas volumes exiting the system (defined as in-franchise customer consumption or Consumption volumes for the purposes of the current Application)[2].

As stated in the Company's pre-filed evidence:

> The residual difference between Sendout and Consumption represents a combination of actual physical gas losses/gains as well as temporary variances resulting from estimation used in both the billing and accounting processes described…".[3]

Said differently, fugitive emissions make up just one of several potential contributors to UFG and are limited specifically to the unintended releases of gases from equipment leaks and third-party damage events.

[1] Exhibit D, Tab 1, pp.14-16.
[2] Exhibit D, Tab 1, pp.16-25.
[3] Exhibit D, Tab 1, p.25.

Accordingly, outside of the Company's existing leak monitoring/detection no UFG-specific testing, monitoring, or measurement has occurred on First Nations reserves or within any other areas of the Company's service territory. Similarly, outside of the proposed Fugitive Emissions Investigation Plan no such UFG-specific testing, monitoring, or measurement is planned within any area of the Company's service territory in the future.[4]

Potential contributing sources of UFG that have been investigated or are being considered for future investigation are detailed in Exhibit D, Tab 1, including:

- Section 1.4 – 2023/2024 UFG Learnings and Observations
- Section 2: Impact of No Bill Customer Volumes on UFG
- Section 3: Impact of Transmission & Other High-Pressure System Linepack on UFG

Please see the response to parts d) and f) below, for a listing of these initiatives and specific references to the Company's pre-filed evidence dealing with each of them. At this time, the Company does not foresee the need to conduct UFG-specific testing, monitoring, or measurement on First Nations reserves as part of such investigations.

d) and f)

Please see the responses to parts b) and e) above, for discussion regarding the distinction between UFG volumes and fugitive emissions as well as for references to potential contributing sources of UFG and UFG-related investigations contemplated by the Company.

Table 1 lists the potential contributing sources of UFG that have been investigated or are being considered for future investigation, as described in the Company's pre-filed evidence. Table 1 also specifies whether or not each potential contributing source is emissions-related. Potential contributing sources that are not emissions related would not involve the survey, identification, measurement, or classification of emissions since physical gas is not released from the natural gas system as part of these processes.

Please see the response at Exhibit I.STAFF-7 part d), for quantification of the volumetric impacts associated with the potential contributing sources of UFG set out in Table 1. Please see the response at Exhibit I.ED-9 part a), for Enbridge Gas's total annual fugitive emissions for the past five years.

[4] Please see the response at Exhibit I.MC-7 parts h) – i), for additional detail regarding fugitive emissions-related engagements.

Table 1
UFG-related Works, Observations, and Learnings

Line No.	Reference	Initiative/Investigation	Emissions Related	Non-Emissions Related
1	Exhibit D, Tab 1, Section 1.3, pp. 16-28	Standard Billing, Estimation, and Annual UFG Related Processes		x
2	Exhibit D, Tab 1, Section 1.4, pp. 29-30	Participation in Industry Groups/Associations, & Cross-Functional Measurement Groups		x
3	Exhibit D, Tab 1, Section 1.4, pp. 30-31	Work to Update Gas Quality Parameters		x
4	Exhibit D, Tab 1, Section 1.4, pp. 31-32	Work to Eliminate a Backlog of Leaks	x	
5	Exhibit D, Tab 1, Section 1.4, pp. 32-33	Various Meter Reading Campaigns & Initiatives		x
6	Exhibit D, Tab 1, Section 1.4, pp. 33-35	Vacant Premises Backlog		x
7	Exhibit D, Tab 1, Section 1.4, pp. 35-38	Assessment of Storage Inventory Audits and Adjustments		x
8	Exhibit D, Tab 1, Section 1.4, pp. 38-39	Advanced Metering Infrastructure		x
9	Exhibit D, Tab 1, Section 1.4, p. 40	Pressure Elevation Factors		x
10	Exhibit D, Tab 1, Section 1.4, pp. 40-41	Loss of Containment	x	
11	Exhibit D, Tab 1, Section 1.4, pp. 42	Measurement Integration		x
12	Exhibit D, Tab 1, Section 1.4, pp. 43-44	Large Volume Customer Measurement for Power Generation		x
13	Exhibit D, Tab 1, Section 1.4, p. 44	Operational Emissions Reductions	x	
14	Exhibit D, Tab 1, Section 2, pp. 44-48	Impact of No Bill Customer Volumes on UFG		x
15	Exhibit D, Tab 1, Section 3, pp. 48-58	Impact of Transmission & Other High-Pressure System Linepack on UFG		x
16	Exhibit D, Tab 1, Section 4, pp. 59-68	The Fugitive Emissions Measurement Plan Project	x	

g) As indicated in the Highwood Report,[5] customer meter sets are the main contributor to Enbridge Gas's fugitive emissions.

h) No. Enbridge Gas does not report UFG as part of provincial and federal GHG reporting programs. As discussed in the responses to parts b) and e) above, fugitive emissions are one of several contributors to UFG. Fugitive emissions are reported within Enbridge Gas's GHG emissions inventory in accordance with provincial and federal GHG reporting programs.

[5] Exhibit D, Tab 1, Attachment 1, p. 47.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

• Exhibit D, Tab 1, p. 6

Preamble:

EGI provides historical UAF volumes for EGD Rate Zone.

Question(s):

a) Please provide a map of the EGD Rate Zone and the Union Rate Zone.

b) What accounted for the extreme drop in UAF Volumes in 2023 compared to the previous five years?

Response:

a) Please see service area maps on the Company's website at the following link: https://www.enbridgegas.com/storage-transportation/doing-business-with-us/service-area-pipeline-maps.

b) Please see the response at Exhibit I.STAFF-7 part d), for quantification of the volumetric contributions associated with potential contributing sources of UFG and for explanation of the Company's UFG-related investigations to date. Enbridge Gas does not yet possess a comprehensive and accurate understanding of all potential contributing sources of UFG or their respective contributions from year to year. However, the Company has formed a UFG team to identify, investigate, and mitigate contributing sources of UFG and to develop long-term and sustainable governance, monitoring, and reporting.

UFG variation experienced from one year to the next is the culmination of many potential contributing sources, including but not limited to:

- accounting/billing processes,
- measurement uncertainty, and

- customer demand (influenced by common macro-economic, geo-political and/or national/continental weather trends).

UFG variation experienced from year to year as a result of such contributing sources can be categorized as either correlated or uncorrelated.

As described at Exhibit D, Tab 1, Section 1.3, pages 16-28, meter estimates, cycle billing, and No-Bills are examples of contributing sources which have impacts that are correlated from one year to the next. When such contributing sources with correlated impacts drive lower reported Consumption levels at the end of one year, UFG will increase (the opposite is true with respect to Sendout related contributing sources). Consequently, UFG levels in the following year would be expected to be suppressed (or increased with respect to Sendout related contributing sources).[1]

As described at Exhibit D, Tab 1, Section 1.4, page 30, work to update Gas Quality Parameters is an example of a contributing source which has an impact that is uncorrelated from one year to the next (i.e., reduces UFG every year going forward).

[1] Please see Exhibit.I.FRPO-20 for an example.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

Exhibit D, Tab 1, pp. 14-15
Highwood Report, 48

Preamble:

EGI provides information on customer meter sets and notes that it investigates any monthly volume variance between custody transfer and check metering volumes that exceeds +/- 2%.

EGI provides a breakdown of customer meter sets by emissions and activity factor.

Question(s):

a) Do industrial customer meter sets (large consumers) emit more fugitive emissions than small household meter sets?

b) If yes to a), could the industrial/commercial meter sets be prioritized based on Enbridge's knowledge of customer consumption? For example, is a high volume customer likely to have a higher volume of fugitive emissions at the meter set?

c) Please provide a list of all variances exceeding +/- 2% in 2022 and 2023, including component type, estimated gas emitted, and whether a repair was completed.

d) Does Enbridge have the data to rank commercial/industrial customers from highest consumption to lowest consumption?

e) Would Enbridge be willing to conduct a pilot study focused on measuring meter sets at the highest consumption commercial/industrial customer sites?

Response:

a) As outlined in the Highwood Report,[1] Enbridge Gas does not currently measure emissions from customer meter sets. Emissions are calculated using national industry-average emission factors. The published emission factor for industrial meter sets is higher than the emission factor for residential meter sets, implying higher emissions per component for industrial meter sets.

b) and e)

The published emission factors used by Enbridge Gas for industrial and residential meter sets are based on measurement campaigns conducted across Canada and may not be reflective of the Company's specific system emissions. Part of the preliminary pilot work proposed by Enbridge Gas, pending OEB approvals, includes prioritizing the most material emission sources with the highest uncertainties in order to develop company-specific emission factors for a subset of distribution assets.[2] This will inform the sampling strategy.

c) Based on MC's references and preamble, Enbridge Gas interprets this question to relate to variances between check measurement and customer site measurement.

There are no check measurement assets at customer stations and the measurement accuracy tolerance of +/- 2% referenced at Exhibit D, Tab 1, Section 1.3, page 15, is unrelated to the unintended release of gas or fugitive emissions. The evidence referenced by MC specifically relates to check measurement assets that Enbridge Gas maintains at gate stations between pipeline systems in order to evaluate the reasonableness of large quantity flows determined by custody measurement onto the Company's systems. This check measurement is not required to comply with Measurement Canada's standards as it is not being used for custody or billing purposes.[3]

At custody transfer points where gas is delivered to the Company, the interconnecting operator (third-party) has custody transfer measurement while Enbridge Gas often has check measurement. Ownership of measurement is reversed at custody transfer points where Enbridge Gas delivers gas to an interconnecting operator (third-party). A small number of exceptions to this rule exist wherein Enbridge Gas regularly analyzes and validates sole source measurement data for consistency to ensure a consistent "quality" of information across all custody transfer points.[4]

[1] Exhibit D, Tab 1, Attachment 1, p.52.
[2] Exhibit D, Tab 1, p.62.
[3] Exhibit D, Tab 1, Section 1.3, p.15, footnote 13.
[4] Exhibit D, Tab 1, Section 1.3, p.15, footnote 14.

d) Yes, Enbridge Gas has consumption data that could be used to rank commercial/industrial customers from highest consumption to lowest consumption.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 25

Preamble:

EGI notes that on a monthly basis, the determination of Sendout includes an entry to record operational blowdowns or flaring associated with compressor facilities as noted in the discussion on Sendout above. By accounting for the volumes associated with these operational blowdowns or flaring, these volumes are removed from Sendout and as such do not contribute to calculated UFG volumes. A similar entry is recorded, where necessary, for blowdowns or flaring associated with capital projects.

Question(s):

a) Where are emissions from blowdowns or flaring recorded?

b) Are emissions from blowdowns or flaring reported in any regulatory filings?

c) Please provide details on who pays for the lost gas from blowdowns or flaring.

Response:

a) The individual events that are included within the Company blowdown gas volumes used in the determination of Sendout, are recorded in the Blowdown Report database. Emissions are calculated based on the annual sum of these volumes.

b) Yes, blowdown and flaring emissions are included within Enbridge Gas's GHG emissions inventory as reported to provincial and federal GHG reporting programs.

c) Please see response at Exhibit I.ED-6 part d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 31

Preamble:

EGI notes that going forward, all class-C leaks will be monitored every 12 months and will be repaired within 18 months of discovery, in accordance with the new integrated Enbridge Gas Leak Standard.

Question(s):

a) Please provide a copy of the new EGI Leak Standard.

b) Please describe the difference between each “class” of leak.

Response:

a) Please see Attachment 1 for the “Leak Operating Standard – June 2024”.

b) Leak classifications are defined and described in Section 4 of Attachment 1.

Leak Operating Standard

1 Purpose

The purpose of this standard is to define:

- The frequency of leakage surveys on all pipeline systems.
- The classification of leaks by degree of hazard.
- The response criteria based on leak classification.

2 Terms and Definitions

The following is a list of terms used in this document and their definitions.

at-risk corrosion area: Corrosion areas, identified by Integrity Engineering, that are at a greater risk of developing corrosion leaks. Some examples include areas that have:

- Historically low cathodic protection
- AC corrosion
- Pipelines identified as having shielding type coatings
- Pipelines with a history of leaks due to corrosion
- Historically unmonitored pipelines

CAC: Customer Attachment Centre

CCFR: Customer Connections field representative

GDS: Gas Distribution and Storage

GHG: greenhouse gas

GPI: gas pipeline inspector

HCA: high consequence area

LDAR: leak detection and repair

MOP: maximum operating pressure

MUB: multi-unit building

- Also referred to as multi-unit residential building, multi-family building, vertical subdivision, or garage header.
- Typically, but not limited to, a multi-storey structure containing four or more storeys (i.e., with cooking, eating, sanitary, and sleeping facilities) which may have in-suite natural gas house piping or house piping serving central equipment service rooms only (e.g., penthouse or basement boiler rooms).

- Depending on age, a building could contain piping and valve features complying with the criteria in the TSSA *Guidelines for the Distribution of Natural Gas in Multi-Family Buildings*.
- Some building configurations may have commercial occupancies on the first one or two floors and dwelling units on the upper floors.

STO: Storage & Transmission Operations

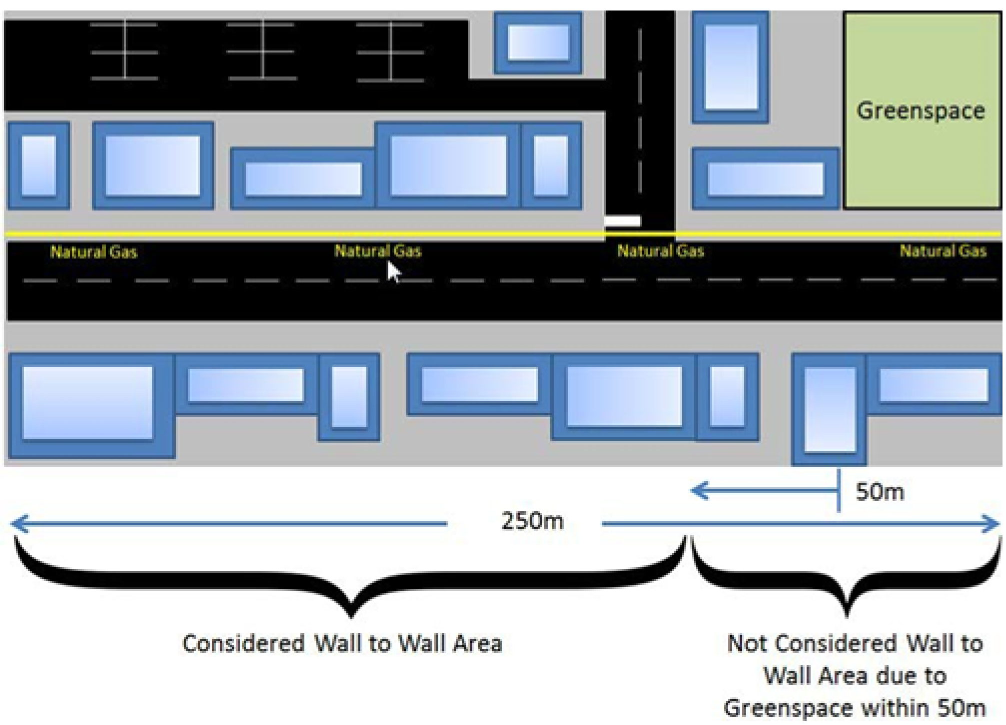
TIMP: Transmission Integrity Management Program

unprotected plant: pipelines that were intentionally designed without cathodic protection

wall-to-wall:

Wall-to-wall is any area where buildings are on both sides of a permanent hard surface material (e.g., asphalt, concrete, interlocking brick, etc.) that restricts natural gas venting to atmosphere for 50 m (164 ft) or more measured parallel to the pipeline is considered a wall-to-wall area. See figure Figure 2-1: Wall-to-Wall Area on page 2 for an example. The presence of concrete expansion joints does not remove an area from being considered wall-to-wall. Tree pits spaced no more than 15 m (50 ft) apart, or a grass median ≥ 0.5 m (1.5 ft) wide, are considered a vent point that may remove an area from being considered wall-to-wall.

Figure 2-1: Wall-to-Wall Area



3 References

- CSA Z662-19, Oil and Gas Pipeline Systems
  - Section 10, Operating, Maintenance and Upgrading,
    - Clauses 10.3.4.1, 10.3.4.2, 10.3.4.3, 10.4.4, 10.6.1.1, 10.6.1.2, 10.6.4.1
  - Section 12, Gas Distribution Systems,
    - Clauses 12.10.3.1, 12.10.3.3
- TSSA, Guidelines for the Distribution of Natural Gas in Multi-Family Buildings (April 2009)
- TSSA FS-238-18, Oil and Gas Pipeline Systems Code Adoption Amendment (Feb 15, 2018)
- Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) SOR/2018-66
  - Sections 26 to 45
- Request for Variance Process

4 Requirements

4.1 Leak Classification and Corrective Actions

Table 4-1: Above- and Below-Grade Leak Classification and Response

Classification	Response
Class A – A leak on any asset that represents an existing or probable hazard to persons or property.	• Designate the leak as an emergency and respond immediately. • The leak must be continually monitored until repaired or mitigated to reduce the leak classification followed by the corresponding monitoring and planned repair.
Class B – A leak on any asset classified as being nonhazardous at the time of detection but has the potential to become hazardous.	• Repair the leak as soon as possible, not exceeding 70 days for below-grade leaks and 30 days for above-grade leaks. For below grade leaks only: • Gas Distribution and Storage (GDS) staff must attend the site of the leak within 7 days to verify the classification and begin pre-work. • Until repaired, the leak must be monitored to ensure it does not intensify to an "A" leak. The first monitor is to be completed within 15 days from the date the leak is discovered. Subsequent monitors are to be completed at a minimum 30-day interval.
Class C – A leak on any asset that is nonhazardous at the time of detection and can be reasonably expected to remain nonhazardous.	• Repair the leak as soon as reasonably possible, not exceeding 30 days [a] for Storage and Transmission Operations (STO) assets or 18 months for Distribution Operations assets. • Until repaired, monitor and reassess the leak at a minimum annually (within 12 months).

Classification	Response
Class N – A natural gas release that has been confirmed through investigation to be the result of a natural process and not related to company infrastructure leaks.	• If the natural gas release poses a risk to the public or property, the local authorities must be notified.

a. C leaks on STO assets that cannot be reasonably repaired within 30 days are to follow the STO leak detection and repair (LDAR) process to determine an allowable extension that meets the Greenhouse Gas (GHG) emissions regulations.

Note

B or C leaks on Distribution Operations assets or B leaks on STO assets, where repair cannot be met within the response timeline, a mitigation plan must be submitted and approved through a Request for Variance prior to the initial due date.

4.2 General Leakage Survey

All piping must be surveyed for leakage in accordance with approved procedures at the frequencies shown in Table 4-2: General Leakage Survey Frequency on page 4. All piping including regulating and gas metering devices, unless such components are specifically delegated to a separate program, must be surveyed for leakage in accordance with approved procedures at the frequencies shown in Table 4-2: General Leakage Survey Frequency on page 4.

Note

Avoid completing surveys when interference of frost caps or severe weather can distort survey results.

Table 4-2: General Leakage Survey Frequency

Pipeline and Location	Survey Frequency		
	< 30% SMYS	Transmission Integrity Management Program (TIMP) not in high consequence area (HCA) or ≥ NPS 16 Vital Main	TIMP in HCA
Indoor facilities (not multi-unit buildings (MUB)) – service extensions into buildings up to the demarcation point (meter) • All installations with inside regulation. • All installations with a 5M rotary meter or larger.	Annual[1]	N/A	N/A
Indoor facilities (not MUBs) – service extensions into buildings up to the demarcation point (meter) for installation with a 3M rotary meter or smaller.	10 year[1]	N/A	N/A

Pipeline and Location	Survey Frequency		
	< 30% SMYS	Transmission Integrity Management Program (TIMP) not in high consequence area (HCA) or ≥ NPS 16 Vital Main	TIMP in HCA
Vertical subdivisions, garage headers, MUBs, and rooftop headers	3 year	N/A	N/A
Unprotected plant and copper survey	Annual	N/A	N/A
PE mains and services[2] and protected steel mains and services[2], [3] - installed prior to 2000	4 year	Annual	Semi-annual
Protected steel mains and services[2], [3] installed after 1999 operating at or above 700 kPa	4 year	Annual	Semi-annual
PE mains and services[2] and protected steel mains and services[2] - installed after 1999 and operating at < 700 kPa	8 year	N/A	N/A
PE mains, services, and protected steel – wall to wall	Annual	N/A	N/A
Class A Stations	Annual		
Class B Stations	4 years		
Class C or D Stations installed prior to 2000 or operating at or above 700 kPa	4 years		
Class C or D Stations installed after 1999 and operating at < 700 kPa	8 years		

1 *Record of a pressure test, by an individual carrying a TSSA gas fitters license or who is a certified gas pipeline inspector (GPI) and covering all indoor piping from inlet to meter, may be accepted as a leak inspection completed within the same calendar year of the pressure test.*

2 *Services made of multiple service pipes must be surveyed based on the highest risk pipe.*

3 *STO sites that fall within the greenhouse gas (GHG) survey requirements must be inspected three times annually. This includes all compressor stations and interconnects to other transmission companies.*

4.3 Building Surveys

Where practical, surveys within buildings should be conducted when the ground surface is frozen. Surveys of rooftops should be conducted during spring or fall and should not be completed during inclement weather.

4.4 Wall-to-Wall Surveys

Where practical, surveys in wall-to-wall areas should be conducted in advance of the ground becoming frozen.

4.5 Special Surveys

Special surveys are to be conducted for known integrity deficiencies associated with specific types or vintages of pipes or fittings and may include at-risk corrosion areas. The limits of the area affected and the increased survey frequency for the condition will be provided by Integrity Management.

A special leak survey of mains and services will be considered before major street repairs or other major construction in the vicinity of gas pipelines. A leakage survey should also be considered after completion of any major construction projects in the vicinity of gas pipelines.

At the discretion of regional management, more frequent surveys may be required on certain pipelines in areas of unstable soil condition, areas of frequent construction activity, or other atypical circumstances.

A mandatory leak survey is required prior to and after the completion of any blasting that takes place within 30 m of a gas pipeline.

After a large flooding event, tornado, or any significant weather event, consideration is given to completing targeted leak surveys in the affected area.

A mandatory leak survey is required prior to, and following, all increases to piping maximum operating pressure (MOP).

5 Document Governance

For document governance purposes, the following tables capture important information related to this document.

Document Control

Category	Value
Owned by:	Engineering department
Review interval:	Every 5 years

Revision History

June 7, 2024 Release

Release Date	Version	Project Number	RFC Number	Prepared By	Approved By
2024-06-07	2.3.0	n/a	5984	Roshan Lawrence Perera, Sr Pipeline Engineer, Distribution Pipeline	Bradley Clark, Director of Engineering

Doc ID	Scope	Document & Section	Summary of Changes
ST-17-96A5-955A	GDS	Leak Operating Standard, Section 3.1	Class B response modified and edits
		Section 3.1	Class C removed "non-plastic"

March 30, 2022 Release

Release Date	Version	Project Number	RFC Number	Prepared By	Approved By
2022-03-30	2.2.0	n/a	RFC 4930	Hooman Zahedi, Supervisor Pipeline Engineering Integration	Tracey Teed Martin, Engineering Director, Engineering & Storage & Transmission Operations (STO)

Doc ID	Scope	Document & Section	Summary of Changes
ST-17-96A5-955A	GDS	Section 3.2 - General Leakage Survey	Updated 1st paragraph and Table 3-2.
		Sections 4.3 and 4.4	Sections deleted.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 38

Preamble:

EGI indicates that it is committed to Advanced Metering Infrastructure ("AMI") and advised that it plans to file a stand- alone AMI application as soon as practicable that will request approval from the OEB for funding and to implement an AMI solution.

Question(s):

Please describe what AMI is and whether it will assist in addressing fugitive emissions.

Response:

Enbridge Gas is committed to deliver the highest standards of service within natural gas metering and leveraging the functionality of AMI which will enhance the safeguards within our pipeline network and ensure that we can continue to ensure the safety of our customers as well as providing timely and accurate billing through remote data collection.

AMI is a comprehensive system that integrates "smart" meters, communication networks and data management systems to provide real-time monitoring and management of energy usage. By enabling two-way communication between the utility and the customer, AMI facilitates precise measurement of natural gas consumption. The infrastructure supports accurate customer billing, enhanced consumer service and will empower customers to optimize their energy usage.

AMI can play an important role in identifying and mitigating fugitive emissions within a natural gas utility. By providing granular (e.g. hourly) real-time flow data and consumer consumption patterns, AMI can assist in detecting anomalies that may indicate leaks or other distribution system integrity issues within the pipeline network. Early detection of these issues enables quicker field technician response times and targeted maintenance within the pipeline network, reducing the volume of UFG. Also, the continuous monitoring capabilities of AMI supports regulatory compliance and sustainability goals by minimizing greenhouse gas emissions from undetected leaks.

Finally, wherein AMI provides precise, real-time monitoring and management of customer consumption the Company expects that AMI could reduce or eliminate the UFG volatility associated with billing based on estimated volumes, as described in the response at Exhibit I.FRPO-27.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

•Exhibit D, Tab 1, pp. 29-44, 55-68

Preamble:

EGI indicates that it has taken the initial steps to establish a team with the express mandate to investigate root causes, make recommendations to reduce and monitor, and to implement a sustainment and governance model for UFG.

EGI outlines the key details of its Investigation Plan to help inform next steps in the development of a broader fugitive emissions measurement program to support the development of a measurement-informed inventory as proposed by the Highwood Report.

Question(s):

a) Please discuss all initiatives EGI has identified and is evaluating to reduce fugitive emissions.

b) Please describe and discuss all initiatives EGI is developing, has or is in the process of implementing to reduce fugitive emissions. In your response, please discuss the expected reduction in fugitive emissions from such initiatives.

c) Did EGI engage with any of EGI's First Nations customers in relation to UFGs? If yes, please discuss how the application and the UFG section of the application was informed by such engagement. If no, please explain why not.

d) Did EGI consider the unique concerns of First Nations regarding UFGs, including fugitive emissions on and near First Nation reserve communities? If yes, please discuss and explain how EGI will address these concerns. If no, please explain why EGI is not aware of the unique concerns of its First Nations customers that live on reserves serviced by EGI.

e) Are there any opportunities for First Nations and/or Indigenous-owned organizations to participate in the initiatives identified by EGI related to monitoring, measuring, and reducing UFG? If yes, please provide details of opportunities specifically targeted to First Nations and/or Indigenous-owned organizations. If no, please explain why EGI is not providing opportunities for First Nations and/or Indigenous-owned organizations to participate in these initiatives and what types of opportunities EGI would be open to enable First Nations and/or Indigenous participation.

f) Are there any opportunities for First Nation training and employment related to emissions monitoring? If yes, please provide details. If no, please explain why no such opportunities exist.

g) What opportunities exist for First Nation and/or Indigenous representatives to participate in the oversight of initiatives relating to the monitoring or reduction of UFGs in First Nation communities and elsewhere?

h) Why is there no specific reference to the considerations of First Nation or Indigenous customers (or their communities) in the sections of EGI's application setting out its proposed Fugitive Emissions Measurement Plan project – i.e., paragraphs 117-132?

i) Why is there no specific reference to the considerations of First Nation or Indigenous customers (or their communities) in the Highwood Report?

Response:

a) and b)

Table 1 provides a list of fugitive emission reduction opportunities that have been identified as part of Enbridge Gas's GHG reduction strategy work. This table is a subset of Table 1 provided in the Company's 2024 Phase 1 Rebasing Application[1] at Exhibit 1, Tab 10, Schedule 8 (including a correction, which was provided at Exhibit I.1.10-Three Fires-3 part b), containing emission reduction initiatives related to fugitive emissions.

[1] EB-2022-0200.

Table 1
Enbridge Gas Fugitive Emission Reduction Initiatives

Line No.	Timing	In-Service Date (ISD)[2]	Project Name	Forecasted Emissions Reduction (tCO_2e)[1]
1	In Flight	2018	Copper Service Replacement	80
2		2019	Direct Inspection and Maintenance Program/Leak Detection and Repair (LDAR)	8,200
9		2021	Fugitive Emissions Management – Reduce Backlogs	16,700
10		2022	Damage Prevention	9,700
13	Medium Term (2024+)	2025	Leak Quantification at Gate Stations	3,300

Notes:
(1) Forecasted annual project emissions reductions once project is fully implemented.
(2) ISD represents the year the project was initiated

c) and g)

Yes, insofar as fugitive emissions are a potential contributing source to UFG, the Company has engaged with First Nations on UFG as discussed in greater detail in the responses to parts h) – i).

As provided in the response at Exhibit I.MC-1 parts b) and e), potential contributing sources of UFG that have been investigated or are being considered for future investigation are detailed in the Company's pre-filed evidence and summarized in the responses to parts d) and f) of the same. Table 1 in the responses at Exhibit I.MC-1 parts d) and f), categorizes contributing sources of UFG according to whether or not they are emissions related. Enbridge Gas has not and does not intend to directly engage with any specific customers regarding non-emissions related sources and related investigations/initiatives as investigations are preliminary at this time, they are unrelated to emissions or the unintended physical release of gas, and the contributing sources are expected to be related to internally managed Enbridge Gas accounting practices, systems, and processes.

Should Enbridge Gas require third party contractors to assist with proposed investigations and initiatives relating to UFG (including fugitive emissions), the Company may provide opportunities for qualified First Nations affiliated businesses and/or qualified Indigenous organizations to participate within its existing contracting processes.

h) and i)

As set out in the complete settlement on item 4 of the Settlement Proposal and accepted by the OEB in its Decision on Settlement Agreement[2] in the 2024 Rebasing Phase 1 application, Enbridge Gas established an Indigenous Working

[2] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.16.

Group (IWG). Since its establishment, Enbridge Gas has provided updates on the Fugitive Emissions Management Plan (FEMP) project during IWG meetings, including fielding questions and engaging in discussion. Enbridge Gas, along with the President of Highwood Emissions Management (Highwood), also met with a representative from Minogi Corp. on May 9, 2024, to discuss Highwood's findings and recommendations. Enbridge Gas offered to host follow-up discussions, should there be any outstanding questions or items for discussion. Enbridge Gas plans to continue to engage with Indigenous groups through the IWG and other mechanisms, to provide updates and seek feedback on the implementation of the FEMP project.

Please also see the responses at Exhibit I.MC-11, for additional discussion regarding engagement with First Nations related to the FEMP project and Highwood Report.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

Highwood Report, p. 13

Preamble:

The Highwood Report defines fugitive emissions as “as leaks from the natural gas system or gas losses due to third-party damages.”

Question(s):

a) Does EGI agree with and use the Highwood Report’s definition of fugitive emissions. If yes, does EGI include any other type of UFG in its definition of fugitive emissions? If no, please provide EGI’s definition of fugitive emissions.

Response:

a) Yes, Enbridge Gas agrees with the referenced definition.

   As discussed in the response at Exhibit I.ED-9 part b), fugitive emissions make up just one of several potential contributors to UFG. Whereas UFG is not a contributor to fugitive emissions.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

Exhibit D, Tab 1, p. 62
•Highwood Report, pp. 44, 50, 57

Preamble:

Compressor stations, and meter/receipt stations are surveyed three times per year using ground-based OGI, and quantification of leak rates is performed using hi-flow sampling.

The Highwood Report notes that the 2022 fugitive emissions from compressor station equipment leaks amounted to 35,308 tCO_2e or 62% of 2022 storage and transmission (STO) fugitive emissions.

The Highwood Report states that fugitive emissions from compressor stations are calculated using direct measurement of leak rates obtained during regulatory LDAR surveys. The total leak volume for a given year is aggregated by taking the hourly leak rates from leak surveys and approximating the duration using the methodology provided in the Ontario GHG Guideline.

Question(s):

a) Please provide an EGI system map (including all compressor stations and other key point sources of fugitive emissions. Please provide the map in a GIS shapefile instead of in PDF format.

b) Please provide the three separate measurements of fugitive emissions for each compressor station over the most recent three years of data collection using the below table. If EGI measures data more or less frequently, please provide all available data for each year.

Compressor Station	Year 1 Fugitive Emissions (tCO_2e)			Year 2 Fugitive Emissions (tCO_2e)			Year 3 Fugitive Emissions (tCO_2e)		
Dawn Compressor Station									
Parkway Compressor Station									
Tecumseh Gas Storage									
Hagar Compressor Station									
Iroquois Falls Compressor Station									
Gas Storage Meter Stations									
Sombra Compressor Station									
Bickford/Sombra Compressor Station									
Lobo Compressor Station									
Bright Compressor Station									
Sandwich Compressor Station									
167 Pool Compressor Station									
Parkway West Compressor Station									
Enniskillen Compressor Station									

Oil Springs East Compressor Station									
Chatham D Compressor Station									
Tipperary Compressor Station									
Waubuno Compressor Station									
Airport Compressor Station									
Dow A Compressor Station									
Heritage Compressor Station									
Edys Mills Compressor Station									
Crowland Compressor Station									
Payne Compressor Station									

c) Please discuss the impacts (both quantity of fugitive emissions and cost for EGI and ratepayers) related to fugitive emissions if the compressor stations with the most associated fugitive emissions were replaced with electric motor drive compression units.

Response:

a) Enbridge Gas respectfully declines to provide the full system maps. These maps are the proprietary information of the Company and are deemed confidential due to the service information and cyber security/terrorism threat that may exist from disclosing such information. Enbridge Gas also does not see the relevance of providing full system maps in relation to the approvals sought from the OEB in this proceeding.

b) Please see Table 1 below for compressor station fugitive emissions for the last three years. The fugitive emissions in Table 1 were calculated using measured leak flow rates from the applicable regulatory LDAR surveys. The annual leak volume for a given reporting year is estimated by taking the measured leak flow rates from the applicable surveys and approximating the leak duration in accordance with the provincial GHG reporting program.

Table 1
Enbridge Gas Historical Annual Compressor Station Fugitive Emissions

Line No.	Compressor Station	2021 (tCO_2e)	2022 (tCO_2e)	2023 (tCO_2e)
1	167 Pool	300	900	400
2	Airport	100	500	200
3	Bickford/Sombra	700	1,700	1,300
4	Bright	200	1,100	1,300
5	Chatham D	10	600	300
6	Dawn	6,100	10,400	7,300
7	Dow A	10	300	200
8	Edys Mills	20	100	100
9	Enniskillen	-	600	300
10	Hagar	1,500	3,400	1,400
11	Heritage	100	100	200
12	Lobo	100	1,300	1,700
13	Oil Springs East	300	600	200
14	Parkway	400	3,500	3,400
15	Parkway West	400	900	2,200
16	Payne	400	10	300
17	Sandwich	200	900	700
18	Sombra	1,000	1,900	1,600
19	Tecumseh	900	3,500	1,500
20	Tipperary	100	600	600
21	Waubuno	40	600	200

NOTES:
- Crowland station and Iroquois Falls station are not included in Table 1 as they are considered distribution stations. The tri-annual leak surveys under the federal methane regulation are not a requirement for distribution stations.

c) Replacing natural gas compressors with electric drive compressors would result predominantly in a reduction of carbon dioxide (CO_2) from the combustion process, not methane (CH_4) from fugitive emissions. Fugitive emissions are associated primarily with the compressor, not the driver. The electric motor drive (EMD) and combustion engine drive use the same compressor technology. Further, Enbridge Gas has service reliability concerns with replacing natural gas-powered compression with electric drives since the fleet design basis requirements would be reliant on the power grid. Many of our sites do not have the appropriate electric power requirements to support an EMD compressor and the costs associated with adding this type of infrastructure would be high. Enbridge Gas has previously identified electric compression as potential initiatives within its Scope 1 and 2 Emission Reduction Plan.[1]

[1] Exhibit EB-2022-0200, Exhibit 1, Tab 10, Schedule 8, Table 2, pg.5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

Highwood Report

Preamble:

Highwood indicates that proposed amendments to regulations, introduced in early 2024, build upon the existing regulations to further reduce methane emissions through more frequent leak surveys, shorter repair timelines and more stringent venting and flaring requirements.

Highwood notes that continuous monitoring is location specific and will require multiple sensors depending on the size of the facility but allow for faster detection and response to leaks

It was recommended in several expert interviews conducted by Highwood Emissions Management that combining different technology types will result in more leak detection events than any one technology alone.
Most methane emissions from transmission systems come from compressor stations, which have unique complexities. For example, un-combusted methane (i.e., "slip") is emitted in compressor exhaust that may introduce noise and obfuscate the ability of screening technologies to discern leaks

Highwood indicates that additional inputs into the calculations include annual equipment operating hours (used to extrapolate emission rates to the total emissions estimate for the year) and gas composition values (which represent the ratio of CH_4 within the total natural gas).

The Highwood Report notes that EGI annually reviews satellite and aerial imagery for any visual changes to the areas within their transmission system. Potential signs of leaks include dead vegetation (which often appear as large circles of dead vegetation, contrasted against otherwise healthy vegetation), melted snow (often appearing as circles of melted snow), and visual encroachment

Question(s):

a) Please explain the existing regulatory requirements applicable to Enbridge and how the proposed amendments would modify those requirements.

b) Do industrial customer meter sets (large consumers) emit more fugitive emissions than small household meter sets? If yes, could the industrial/commercial meter sets be prioritized based on Enbridge's knowledge of customer consumption? For example, is a high volume customer likely to have a higher volume of fugitive emissions at the meter set?

c) Has Enbridge used drone technology to monitor lost gas (e.g. fugitive emissions, flaring, third party, etc.)?

d) Does Enbridge conduct continuous monitoring on any facilities?

e) Which combination of technologies does Enbridge intend to implement?

f) Does Enbridge measure un-combusted methane "slip" at compressor stations? If so, please share the data.

g) How does Enbridge discern between "slip" and leaks?

h) Does Enbridge have the data to rank commercial/industrial customers from highest consumption to lowest consumption?

i) Would Enbridge be willing to conduct a pilot study focused on measuring meter sets at the highest consumption commercial/industrial customer sites?

j) Please explain these calculations by providing an example that breaks down gas composition.

k) How many storage wells does Enbridge own, operate, or otherwise have site control over?

l) Would Enbridge be willing to conduct a pilot study focused on measuring storage well leaks?

m) Does Enbridge know the location of leaking buried pipes?

n) Does an annual review of satellite imagery capture the melted snow at the appropriate time?

Response:

a) The regulation that applies to the upstream oil and gas sector, which includes the transmission and storage segment of the natural gas industry, is *"Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)"*[1] (the methane regulation). The methane regulation was published by ECCC on April 28, 2018, to help reduce methane emissions from Canada's oil and gas sector. In December 2023, the Government of Canada released proposed amendments to the Methane Regulations,[2] expanding the scope of the existing methane regulations by introducing a focus on maximizing emission reductions. The amendments seek to further reduce methane emissions through:

   - More frequent leak surveys: including increasing the LDAR surveys from tri-annually to quarterly for specific facilities, including compressor stations; and the introduction of screening and annual inspections.
   - Shorter repair timelines: including timelines based on specific leak flow rates; and required repair within one year of detection.
   - Stringent venting requirements: venting prohibited, with limited exceptions.
   - Stringent flaring requirements: eliminate routine flaring, with exceptions for health and safety.

   The final amended Regulations are expected to be published in the Canada Gazette, Part II, in late 2024.

b) Please see the responses at Exhibit I.MC-3 parts a) and b).

c) No, Enbridge Gas has not used drone technology to monitor lost gas.

d) Enbridge Gas installs methane detectors in many of its Company-owned station buildings with natural gas piping. Enbridge Gas displays readings from those detectors via a field-mounted display unit to ensure employees can see the values and hear related alarms prior to entering station buildings. Real time readings and alarms from the detectors are also sent to the remote terminal unit (RTU) for monitoring and investigation.

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[1] Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (April 28, 2018) https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-66/.
[2] Regulations Amending the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (December 16, 2023) https://www.canadagazette.gc.ca/rp-pr/p1/2023/2023-12-16/pdf/g1-15750.pdf - page=56.

e) As part of the proposed pilot, Enbridge Gas is seeking to pilot a mobile ground (vehicle) technology for detecting and measuring distribution operations (DO) fugitive emissions on a portion of the DO system, in order to evaluate the technology suitability. Enbridge Gas is also seeking to begin developing company-specific emission factors, expecting to use a handheld flow rate measurement technology, for a subset of DO assets. The outcomes and lessons learned from the pilot will be used to direct future measurement efforts and inform future measurement goals.

f) No, Enbridge Gas does not measure un-combusted methane ‘slip’ at compressor stations. However, the emissions calculation methodology for stationary combustion emissions includes an emission factor for methane, and as such, Enbridge Gas’s GHG emissions inventory accounts for unburned methane slip from its compressor units.

g) Methane slip is a term to describe uncombusted methane as a result of the combustion process and as such methane slip is reported as a component of combustion emissions. Leaks, which are unintentional releases of gas from piping and associated equipment components, are reported as fugitive emissions.

h) Please see the response at Exhibit I.MC-3 part d).

i) Please see the response at Exhibit I.MC-3 part e).

j) Enbridge Gas’s gas composition is utilized to speciate the emissions due to the calculated volume of gas emitted. Please see the Enbridge Gas ‘Learn About Natural Gas’ webpage[3] for the 2023 Enbridge Gas gas composition data, provided to the Ontario Ministry of the Environment, Conservation and Parks (MECP) for use in the calculation of GHG emissions.

The following is a breakdown of the components of this calculation:

$$ER_i = \frac{V \times y_i \times MW_i}{V_{STP}}$$

Where,
ER_i = average emission rate (tonnes/year) of substance i.

V = volume of gas emitted ($10^3 m^3$/year), expressed at standard temperature and pressure (i.e., 15°C and 101.325 kPa).

y_i = mol fraction of the target substance i in the emitted gas volume (kmol/kmol).

[3] https://www.enbridgegas.com/about-enbridge-gas/learn-about-natural-gas

MW_i = molecular weight of the target substance i (kg/kmol).

V_{STP} = volume of 1 kmol of gas at standard temperature and pressure (m^3/kmol).
= 23.6444813 (m^3/kmol).

k) Enbridge Gas owns and operates 368 storage wells.

l) It is premature to commit to any future storage-specific pilot study at this time.

Enbridge Gas's proposed investigation plan, prioritized the measurement of DO fugitive emissions, due to their higher contribution to overall emissions and since the majority of storage and transmission (STO) fugitive emissions are already being measured and quantified.

Enbridge Gas currently inspects storage wells quarterly. This inspection includes examining the well for leaks. If a leak is detected, a plan is developed to repair the leak as soon as practical.

m) Enbridge Gas records the locations of all known leaks. They are identified by a location number, premises ID and\or nearest address in the Company's Work Management system. All work orders associated with the investigation, monitoring and repair of the leak are associated with the original notification by either leak survey or customer call.

n) Enbridge Gas utilizes satellite imagery to review encroachment and monitor visual changes in the vicinity of its transmission pipelines for integrity purposes. In the event that leak indications, such as melted snow or dead vegetation are identified as part of these reviews, it may lead to further investigation, but there is no formal review process for these anomalies. As discussed in the response at Exhibit I.ED-15 part c), the Company's distribution assets are surveyed in accordance with CSA Z662 leak management requirements and Enbridge Gas remains confident in its existing leak survey program.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

Highwood Report
Highwood Report, pp. 95-101

Question(s):

a) Did Highwood engage with any of EGI's First Nations customers in preparing the Highwood Report? If yes, please discuss the engagements that occurred and how this informed the Highwood Report. If no, please explain why not.

b) Is Highwood aware of any concerns or issues specific to EGI's First Nations customers? If yes, please discuss the unique concerns and issues of First Nations and how the Highwood Report addresses and/or considers these concerns and issues. If no, please provide your opinion on the types of concerns and issues that may be of specific concern to EGI's First Nations customers and how these should be considered and addressed by EGI in developing its plans to monitor and reduce fugitive emissions.

c) Do Highwood's recommendations consider the realities of monitoring and measuring fugitive emissions on First Nation reserve communities? If yes, please discuss. If no, please explain how Highwood's recommendations may be updated to reflect the unique circumstances and realities of monitoring fugitive emissions in First Nations reserve communities.

d) Does Enbridge agree to implement all four recommendations from the Highwood Report?

Response:

The following response was provided by Highwood Emissions Management:

a) Highwood did not directly engage with any of Enbridge Gas's customers (First Nations or other), in preparing the Highwood Report. However, in a meeting on May 9, 2024, Highwood did present its report to a representative from Minogi Corp.

b) Highwood was not made aware of any specific concerns raised by Enbridge Gas's First Nations customers. In Highwood's opinion, given our experience, we understand that the types of concerns that may arise from First Nations customers regarding emissions are similar to those of other Enbridge Gas customers, including environmental impacts, health concerns, and climate change implications. Addressing these concerns exceeds the scope of work established for the Highwood Report.

c) The unique circumstances of First Nations communities were not considered as part of the Highwood's recommendations as such circumstances exceed the scope of work established for the Highwood Report.

The following response was provided by Enbridge Gas:

d) Please see the response at Exhibit I.ED-21.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Minogi Corp. (MC)

Interrogatory

Reference:

Exhibit E, Tab 1, p. 25.

Preamble:

EGI notes that in the Union Rate Zones, 2023 OEB-approved rates included $11.6 million in UFG costs (based on forecasted throughput volumes). Based on 2023 actual throughput volumes, Enbridge Gas recovered $16.4 million in UFG costs through rates. In comparison, Enbridge Gas's actual 2023 UFG costs were $20.3 million.

Question(s):

a) Who pays the cost of UFG that is the result of fugitive emissions and what is the dollar value of the fugitive emissions over the system on an annual basis for the last three years?

b) What is the portion of the UFG costs to ratepayers in the Union Rate Zones that are attributable to fugitive emissions?

c) What are the UFG costs to ratepayers attributable to fugitive emissions in the EGD Rate Zone?

Response:

a) The UFG volumes associated with fugitive emissions are recovered in the same manner as the total annual volume of UFG. The forecast cost of UFG is recovered from all customers through rates and/or customer supplied fuel ratios. Variances between actual UFG volumes and forecasted UFG volumes recovered in rates is disposed of through the UFGVA for the Union Rate Zones. Please see the response at Exhibit I.ED-10 part a), for the estimated UFG costs related to fugitive emissions.

b) and c)

Accurately calculating the specific costs of fugitive emissions or any other contributing sources of UFG is extremely complex and time consuming. Therefore, in Tables 1 and 2, Enbridge Gas has produced a simplified illustrative example estimating the historical UFG costs related to fugitives in the Union Rate Zones and the EGD Rate Zone, respectively, for the past 3 years , by applying a calculated ratio (annual fugitive volumes vs total annual UFG volumes) to total annual UFG costs[1]. Please see the response at Exhibit I.STAFF-13, for discussion regarding the impact of lower gas supply commodity costs in 2023 vs. 2022,[2] and the response at Exhibit I.ED-4 parts a) and b), for historical annual UFG volumes and costs.

Table 1
Estimated UFG Costs Related to Fugitive Emissions Union Rate Zones

Year	Estimated Union Rate Zone Fugitive Costs ($ Millions)
2021	1.6
2022	3.2
2023	2.0

Table 2
Estimated UFG Costs Related to Fugitive Emissions EGD Rate Zone

Year	Estimated EGD Rate Zone Fugitive Costs ($ Millions)
2021	3.1
2022	3.7
2023	2.6

[1] Please see the responses at Exhibit I.ED-4 parts a) & b), for historical UFG volume and cost details.
[2] Please note that lower gas supply commodity costs in 2023 relative to 2022 impacted UFG costs across all rate zones.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (OGVG)

Interrogatory

Reference:

General, Deferral and Variance Accounts

Preamble:

EGI has been clearing most of the same set of deferral and variance accounts on an annual basis from 2019 to 2023. It is OGVG's expectation EGI has not made changes to how the accounts operate or how the amounts to be disposed of are allocated to EGI's customer classes

Question(s):

a) Please confirm that for the deferral and variance accounts that EGI is asking to clear for 2023 that existed and have been cleared in previous proceedings for the years 2022 and prior, that EGI is not proposing any methodological changes to how those accounts track costs, nor changes to the way the proposed amounts to be disposed of are allocated amongst EGI's customer classes. If not confirmed, please list the accounts where there is change relative to previously approved dispositions and detail the changes in how costs have been tracked and/or how the amounts to be disposed are being allocated amongst EGI's customer classes.

Response:

a) Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (OGVG)

Interrogatory

Reference:

Exhibit C Tab 1 Page 24 paragraph 7
Ontario Underground Infrastructure Notification System Act, 2012, S.O. 2012, c. 4, sections 6, 8.
O. Reg. 92/14: GOVERNANCE OF THE CORPORATION, section 2.

Preamble:

Locate costs have increased due to the new legislated locate delivery timelines resulting from Bill 93. Enbridge Gas's average locate delivery times were 13 days and 15 days in 2021 and 2022 respectively. Bill 93 legislates a 5 day locate delivery mandate and introduces administrative penalties for non-compliance.

Ontario Underground Infrastructure Notification System Act, 2012, S.O. 2012, c. 4
(as it existed from March 31, 2014, to April 13, 2023)

Where infrastructure affected by dig

6. (1) If a member of the Corporation receives a notification from the Corporation about a proposed excavation or dig that may affect underground infrastructure owned by the member, the member shall,

(a) mark on the ground the location of its underground infrastructure and provide a written document containing information respecting the location of the underground infrastructure; or

(b) state in writing that none of its underground infrastructure will be affected by the excavation or dig. 2012, c. 4, s. 6 (1).

Member to respond within five days

(2) The member shall make all reasonable attempts to do the things required by subsection (1) within five business days of the day the member receives notification about the proposed excavation or dig, unless there is a reasonable expectation that the excavation or dig will not start within 30 business days of the day the member receives the notification. 2012, c. 4, s. 6 (2).

Penalties

8. A person or entity who does not comply with section 5, 6 or 7 is guilty of an offence and on conviction is liable to the fine set out in the regulations made under this Act. 2012, c. 4, s. 8.

O. Reg. 92/14: GOVERNANCE OF THE CORPORATION

Fine for non-compliance

2. The amount of $10,000 is prescribed as the amount of the fine mentioned in section 8 of the Act. O. Reg. 92/14, s. 2.

Question(s):

a) Given that, under the Ontario Underground Infrastructure Notification System Act as it existed from March 31, 2014, to April 13, 2023, there was both a 5-business day delivery timeline for the provision of locates and an administrative penalty of $10,000 for non-compliance with that limit, please provide further explanation as to how the enactment of the Getting Ontario Connected Act caused material increases in locate costs.

b) Please explain how EGI's average locate delivery times persisted at 13 to 15-day levels given the existence of the 5-business day delivery timeline and administrative penalty of $10,000 under the Ontario Underground Infrastructure Notification System Act as it existed from March 31, 2014, to April 13, 2023.

c) When did EGI become aware of the proposals that became the Getting Ontario Connected Act?

d) What did EGI do, if anything, to try and mitigate the impact of the Getting Ontario Connected Act on locate costs?

Response:

a) and b)

Although a 5-business day delivery timeline and administrative penalty existed in past legislation, it was on the basis of "all reasonable attempts". Within the industry "all reasonable attempts" included a delay in locates with regards to things like weather events or staffing shortages. In the previous legislation, Enbridge Gas had never received an administrative penalty for non-compliance with the locate delivery requirements.

With the enactment of Bill 93 the provision "all reasonable attempts" was removed from the legislation resulting in absolute liability, meaning Ontario utility owners would need to comply with the 5-business day delivery timeline or be non-compliant with the legislation. Due to these legislative changes, the locating industry was required to adapt to meet higher demands for locate deliveries. Enbridge Gas, and other Ontario utility owners were now required to ensure Locate Service Providers (LSPs) reduce average locate delivery times significantly. With locating recognized as having a requisite skills requirement, and LSPs needing to attract and retain additional skilled locating workforce to meet the legislated 5-business day delivery requirement, locate costs increased significantly.[1]

c) Enbridge Gas was made aware of the proposals in March 2022.

d) Enbridge Gas continually evaluates the locating process and seeks to drive efficiencies and reduce overall locating costs. Enbridge Gas has increased locate savings annually through the locate screening center, alternate locate agreements (ALAs) with excavators, and dedicated locator agreements, totaling more than $13 million in 2023. ALAs are agreements with specific excavators permitting defined work without the need of an Enbridge Gas field locate. This reduces the total locates Enbridge Gas needs to complete and represents the majority of the 2023 savings quoted above. Additional efforts to reduce locating costs include excavator education campaigns, stakeholder engagement, emerging technologies, and process efficiencies.

[1] https://www.rds.oeb.ca/CMWebDrawer/Record/792328/File/document

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Enbridge Gas requests that certain information included at Exhibit D, Tab 1 Schedule 6 be treated as confidential under the OEB's Practice Direction on Confidential Filings [A2 Page 3].

Question(s):

Has Enbridge filed the request for confidential treatment of certain information in this Application, as noted above? If not, when is this expected. If yes, please provide a copy.

Response:

Enbridge Gas has included the request for confidential treatment of certain information in the cover letter to this application filed on May 31, 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Unregulated Adjustments (Line 24) increased by $8.5 million driving lower O&M due to incremental unregulated costs primarily related to Enbridge RNG projects, Enbridge Sustain, and the Carbon Capture project. [B/3/1 Page 4]

Question(s):

a) Please provide details related to each of the items noted by Enbridge above, including the impact of each item and reconciling it as a portion of the $8.5 million.

b) Please explain for each of the three categories above why these were done through the regulated utility and then adjusted, rather than just performing each of those activities entirely outside the regulated utility.

Response:

a) Details for each of the items are provided below:

Table 1
Unregulated Adjustments

Line No.	Item	2023 Spend (in millions)	2023 vs 2022 (in millions)
1	Enbridge RNG projects	2.8	2.7
2	Enbridge Sustain	6.4	3.6
3	Carbon Capture & Storage (CCS)	1.1	1.1

The remainder of variances totaling $8.5 million are related to various smaller items.

The driver for the incremental cost of Enbridge RNG Projects is because the Dufferin RNG plant went into operation on March 10, 2023, resulting in operating charges.

The driver for the incremental cost of Enbridge Sustain is because additional resources are required to evolve and develop the Enbridge Sustain business.

The driver for the incremental cost of CCS is due to Enbridge Gas starting to evaluate CCS in 2023.

b) Enbridge Gas clarifies that the starting point for evidence in Exhibit B, Tab 3, Schedule 1, as well as the Utility Income in Exhibit B, Tab 1, Schedule 2, are the results of Enbridge Gas Inc. the legal entity and not the utility. Line 24 of Exhibit B, Tab 3, Schedule 1 represents total Enbridge Gas Inc. O&M, with subsequent adjustments in lines 19 through 25 to remove O&M pertaining to unregulated operations and other adjustments that pertain to Enbridge Gas but not the utility. The result is that the amount remaining after these adjustments is what pertains to the utility operations. Therefore, the three categories as noted above are not “done through the regulated utility” but through Enbridge Gas Inc. the legal entity and segregated from the utility. These activities are permitted under Enbridge Gas’s Undertakings and related Minister’s Directives.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

a) Please provide the OEB approved description for the IRP Operating Costs Deferral Account and how Enbridge has determined that account description applies to amounts proposed to be cleared in 2023.

b) Please provide the current OEB approved description for the IRP Operating Costs Deferral Account (if different from the response to part a) and indicates how that varies from the description outlined in part a.

Response:

a) IRP Operating Costs Deferral Account, as defined and approved in the Integrated Resource Planning Proposal, states:

> The purpose of the Integrated Resource Planning (IRP) Operating Costs deferral account, as established in the Board's EB-2020-0091 Decision and Order, is to record incremental IRP general administrative costs, as well as incremental operating and maintenance costs and ongoing evaluation costs for approved IRP Plans. Operating costs associated with approved IRP Plans would also include all enabling payments to service providers, made as part of the IRP Plans.[1]

Please refer to Exhibit C, Tab 1, page 14, paragraphs 4 - 5 and Table 1 as to why Enbridge Gas determined the amounts proposed to be cleared in 2023 are applicable[2].

b) The current approved description of the account IRP Operating Costs Deferral Account, as defined in the Interim Rate Order for Enbridge Gas 2024 Rebasing – Phase 1 application, states:

> This account records incremental IRP general administrative costs, as well as incremental operating and maintenance costs and ongoing evaluation costs for approved IRP Plans. Operating costs associated with approved IRP Plans also includes all enabling payments to service providers, made as part of the IRP Plans. This account will also record offsetting avoided operating costs that relate to facilities that are delayed, avoided, or downsized by an IRP Plan.[3]

[1] EB-2020-0091, Draft Accounting Orders, August 12, 2021, p.1.
[2] Exhibit C, Tab 1, pp.14-22.
[3] EB-2022-0200, Rate Order, Appendix C, p.40.

This definition varies from the definition in part a), as it now includes that “[t]his account will also record offsetting avoided operating costs that relate to facilities that are delayed, avoided, or downsized by an IRP Plan.”

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

C1 Page 4.

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

Question(s):

a) For each of the items above, please provide the OEB Decision reference approving the treatment for the merged Enbridge Gas Inc.

b) If specific OEB approval has not been provided for any item in the table above, please indicate when Enbridge expects to seek approval for the change in treatment.

Response:

a) and b)

In the 2024 Phase 1 Rebasing application, Enbridge Gas described its proposal regarding accounting policy changes resulting from amalgamation and disposal of the APCDA balance:

> Enbridge Gas has recorded the revenue requirement impacts of accounting policy changes resulting from amalgamation for EGD and Union in the APCDA. If approved, balances up to December 31, 2023, will be disposed of starting January 1, 2024. Beyond 2023, the revenue requirement impact of the accounting policy changes have been included in the 2024 forecast cost of service filed as part of this Application. Accordingly, the APCDA will no longer be required to capture impacts beyond 2023, and Enbridge Gas is requesting closure following disposition of the final APCDA balance.[1]

Subsequently, with the OEB's approval of the 2024 Phase 1 Rebasing Settlement Agreement[2] and Decision on unsettled items, which approved of 2024 O&M and capital budgets underpinned by the referenced harmonized accounting policies noted in evidence, and the discontinuance of the APCDA, it is Enbridge Gas's understanding that the proposed harmonized accounting policies were approved.

[1] EB-2022-0200, Exhibit 9, Tab 2, Schedule 1, pp.4-5.
[2] EB-2022-0200, Settlement Agreement, dated August 17, 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

C1 Page 5

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

Question(s):

a) For each of the items above, please provide the OEB Decision reference approving the treatment for the merged Enbridge Gas Inc.

b) If specific OEB approval has not been provided for any item in the table above, please indicate when Enbridge expects to seek approval for the change in treatment.

Response:

a) and b)

Please see the response at Exhibit I.PP-4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

C1 Page 15, Table 1

Line No.	Item	Description	Millions ($)
1	Incremental FTE's	Salaries, loadings and expenses	$2.680
2	East Kingston Creekford Rd Project	Project costs	$0.278
3	Posterity Group	Model enhancement costs	$0.113
4	Stakeholder Engagement	Promotion and materials	$0.010
5	Total Requested for Clearance		$3.081
6	IRP Pilot Projects	Not Requested for Clearance	$0.061
7	Total in IRP Operating Cost DA		$3.142

Question(s):

a) Please confirm that all costs related to the East Kingston Creekford Rd Project were incurred in 2023. If any costs related to the project were incurred outside 2023, please provide the full project costs segmented by year and cost centre they were (or will be) allocated to.

b) Please provide a copy of the East Kingston Creekford Rd Project completion (or equivalent) report or related documentation (presentation, etc.).

c) Please provide the start date and end date for the East Kingston Creekford Rd Project and also when the amounts summing to the project costs of $0.278 million were posted to the IRP Operating Costs Deferral Account.

d) Please confirm the Capital estimate for the East Kingston Creekford Rd Project (or alternate name if applicable) that was used for Capital planning (AMP) purposes and provide the source reference.

e) Please provide a copy of the materials (report, slides, memo, email and/or SOW) indicating the scope and delivery of work performed by Posterity Group for the "Model enhancement costs" noted in Table 1.

Response:

a) Confirmed. All East Kingston Creekford Rd Project costs in the referenced Table were incurred in 2023. Please see Exhibit I-STAFF 3 part a) for additional details on the total costs incurred related to this project.

b) There is no project completion documentation.

c) The start and end date of the East Kingston Creekford Rd Project is 2022 to 2024. The amounts summing to the project costs of $0.278 million were posted to the IRP Operating Deferral Account in 2023.

d) The Capital estimate for the East Kingston Creekford Rd Project was $24.3 million, referenced as "SRP_LUG East_Kingston_Creekford Rd_Reinforcement_NPS8_6200m_6895kPa" in the 2023-2032 Asset Management Plan – Appendix A.[1]

e) Please see Attachment 1 for the scope of work related to model enhancement work undertaken by Posterity Group.

[1] EB-2022-0200, Exhibit 2.6.2 Appendix A, p.25.

POSTERITY
GROUP

Scoping Document:
2022 IRPA Analysis Support

Date: June 8, 2022

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Contents

1 Background and Objectives 1

2 Work Packages to Address EGI's Core Priorities 2

2.1 Work Package 1 – Reference Case Updates 2

2.2 Work Package 2 – Load Shape Re-Calibration 2

2.3 Work Package 3 – ETEE Measure Assumption Updates 3

2.4 Work Package 4 – IRPA Potential Scenarios Methodology 4

2.5 Work Package 5 – General Support 5

2.6 Work Package 6 – Witness and Interrogatory Support 5

3 Overall Timeline 6

4 Estimated Level of Effort & Budget 7

1 Background and Objectives

Enbridge Gas Inc. (EGI) is developing an approach to align its facility expansion and reinforcement planning activities with the IRP Framework. This involves incorporating integrated resource planning alternative (IRPA) screening into its asset management planning (AMP) process and performing IRPA analysis for upcoming leave to construct (LTC) applications.

EGI made initial investments to create the foundation of an IRPA dataset and modelling approach (prior to the IRP Framework being developed) and now needs to make further investments to:

- Improve the rigour and credibility of EGI's IRPA analysis in the eyes of intervenors and the OEB
- Facilitate an approach to undertake numerous IRPA assessments routinely over the next two years

To minimize initial investments before the IRP Framework was established, Posterity Group worked with EGI to develop load shapes and apply these profiles to a modified version of the 2019 Achievable Potential Study (APS) dataset and reference case. These updates allowed our team to estimate peak demand reduction potential from enhanced targeted energy efficiency (ETEE) measures.

Over a series of conversations between Posterity Group and EGI in 2022, EGI has developed a list of priorities that address misalignment between the IRP Framework and the legacy IRPA dataset and modelling approach. Priorities are grouped into six work packages that are covered in more detail in the following section:

- Work Package 1 - Reference case updates
- Work Package 2 - Load shape re-calibration
- Work Package 3 - ETEE measure assumption updates
- Work Package 4 - IRPA potential scenarios methodology
- Work Package 5 - General support
- Work Package 6 – Witness and Interrogatory Support

2 Work Packages to Address EGI's Core Priorities

The proposed support activities have been organized into six Work Packages, described below. EGI may choose to proceed with any combination of these Work Packages.

2.1 Work Package 1 – Reference Case Updates

Value and outcomes for EGI: Several structural updates and data refreshes have been applied to the reference case originally developed for the 2019 Achievable Potential Study (APS) to support internal analysis and various filings. To improve accuracy of future IRPA analysis, the base year should be calibrated to EGI's most recent complete year of actuals, and the reference case growth forecast should be updated to reflect EGI's most recent 10-year forecast.

Activities:

- Update model for EGI peak hour/day loads using updated 10-year growth forecast and more recent consumption data
- Review rate classes under each customer type for accuracy
- Confirm whether any larger customers were removed from the Posterity analysis

Level of Effort Estimate:

- 115 Hours

Timeline Estimate:

- 2 weeks
- Complete half month after initiation

2.2 Work Package 2 – Load Shape Re-Calibration

Value and outcomes for EGI: EGI requires an end-use model for its entire service territory with updated load shapes for each unique end-use and facility type within each sector and across all regions. This activity will involve recalibrating load shapes at the sector-rate zone level in collaboration with EGI's Distribution, Optimization and Engineering (DOE) group. The goal will be to develop peak hour and peak day outputs that DOE understands and trusts. The implications of measures on load shapes will also be evaluated.

Activities:

- Align average peak hourly flows for different customers in the IRP model to DOE model assumptions. Also confirm how these flows were determined and what the distribution looks like.
- One of the load shape memos states "The estimates of system peak hour vs. peak day load in Ontario may not be perfectly accurate (e.g., the ratio of 1.2 for peak hour divided by average hourly demand on the peak day)." Confirm where this ratio came from and how was it used?
- Develop heating profiles for all customer types with an associated temperature profile in the model. When considering peak day/hour for heating profiles we have to extrapolate

these profiles to generate a profile for the region specific design temperature (DOE has experience in this and can inform best practice). Also, assess how certain measures impact base versus heating loads and include that breakdown in the output data.

- Assess whether certain measures that reduce space heating should do so by impacting the base temperature (temperature where heating starts) on heating profiles. Some or all of the annual savings should be converted to peak savings by adjusting the profiles. The percent of annual savings to be used to adjust the profile must be adjustable. This will help inform the difference in peak hour vs annual savings.

Level of Effort Estimate:

- 190 Hours

Timeline Estimate:

- 3.5 weeks
- Complete 1 month after completion of WP1

2.3 Work Package 3 – ETEE Measure Assumption Updates

Value and outcomes for EGI: Several updates have been made to the APS energy efficiency measure assumptions to support EGI's DSM planning team, but further work is required to update ETEE measures to reflect differences between the demand side management program framework and the IRP Framework.

Activities:

- Determine how to treat/estimate costs depending on program delivery method
- Review methodology for determining which measures impact peak
- Output detailed list of measure assumptions included in the IRP ETEE model
- Review instances where the model outputs negative savings and develop approach on how to interpret and use these results
- Assess whether measure savings for commercial customers should be based on floor area or accounts
- Some measures were not included because of baseline assumptions, which is relevant for DSM, but maybe not a concern to IRP ETEE programs. Provide further consideration of how baselines are incorporated for the IRP ETEE model (versus the DSM model)
- Assess whether measures enhancements are needed for the IRP ETEE Model

Level of Effort Estimate:

- 225 Hours

Timeline Estimate:

- 3 weeks
- Complete 2 months after initiation

2.4 Work Package 4 – IRPA Potential Scenarios Methodology

Value and outcomes for EGI: This package of activities will result in methodological improvements to the IRP ETEE model scenarios, which will facilitate future IRPA analyses.

Activities:

- Confirm whether Budget Solver should be optimized for peak savings or annual savings
- Provide DSM business as usual scenario to compare ETEE potential to: align measures in this scenario with DSM program offerings (including measures for new construction); output detailed list of measure assumptions
- Determine appropriate net to gross (NTG) values and apply these values to the results of the IRP ETEE model to develop gross budgets.
- Determine how to account for the difference between achievable and economic potential and whether this is different than the 'derating factors'
- Evaluate in more detail the possibility of assessing technical potential (beyond DSM in AMP reference case) and applying derating factors and determine what this exercise would entail. Assess Use of Scenario and determine whether technical potential the most appropriate scenario to use initially for the IRP model.

Level of Effort Estimate:

- 315 Hours

Timeline Estimate:

- 6 weeks
- Complete 2 months after completion of WP2

2.5 Work Package 5 – General Support

Value and outcomes for EGI: The main outcome of this work package will be a public-facing report for the IRP ETEE Model which will provide EGI with further transparency and defensibility of its approach.

Activities:

- Develop a public-facing report for the IRP ETEE Model
- Other activities: provide ad-hoc support, AMP screening support, and ongoing reporting support

Level of Effort Estimate:

- Public-facing report for IRP Model: 80 hours
- Block of hours for ad-hoc support: 120 hours
- Total: 200 hours

Timeline Estimate:

- Public-facing report for the IRP ETEE Model to be completed within half of a month of completion of WP4
- Ad-hoc support to be provided as required

2.6 Work Package 6 – Witness and Interrogatory Support

Value and outcomes for EGI: The main outcome of this work package will be expert witness and interrogatory support during Technical Working Group meetings and/or Hearings.

Activities:

- Prepare for and provide expert witness support

Level of Effort Estimate:

- Total: 100 hours

Timeline Estimate:

- Support will be provided on an on-going basis, as required.

3 Overall Timeline

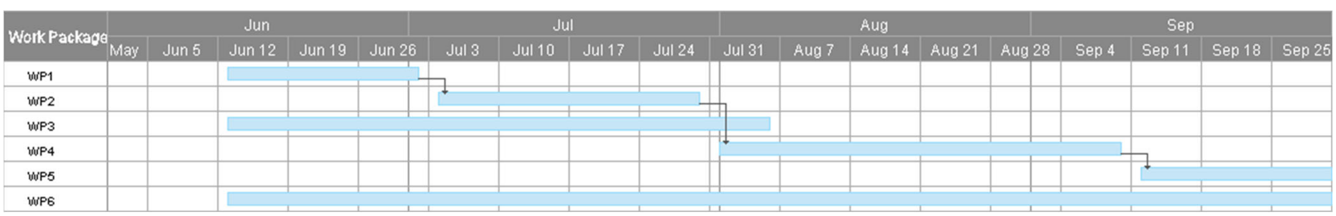
The estimated timelines to complete each work package are shown in Table 1. Some work packages must be complete sequentially, such as WP1 and WP2, while others are independent and can be started earlier, such as WP3. A project Gantt chart is shown in Exhibit 1.

Model updates and reporting will be completed within 3.5 months.

Table 1 Timeline Estimates by Work Package

Work Package	Timeline Estimate
WP1 - Reference Case Updates	1/2 month after initiation
WP2 - Load Shape Re-Calibration	1 month after completion of WP1
WP3 - ETEE Measure Assumption Updates	2 months after initiation
WP4 - IRPA Potential Scenarios Methodology	2 months after completion of WP2
WP5 - General Support	Public-facing report to be completed within 1/2 month of completion of WP4
WP6 - Witness and Interrogatory Support	Provided on an on-going basis, as required

Exhibit 1 Project Gantt Chat



4 Estimated Level of Effort & Budget

The level of effort estimates and associated budgets for Work Packages 1 through 6 are summarized in Table 2.

Table 2 Level of Effort and Budget

Work Package	Level of Effort (Hours)	Budget [redacted]	Budget [redacted]	Total Budget
WP1 - Reference Case Updates	[redacted]	[redacted]	-	[redacted]
WP2 - Load Shape Re-Calibration	[redacted]	[redacted]	-	[redacted]
WP3 - ETEE Measure Assumption Updates	[redacted]	[redacted]	-	[redacted]
WP4 - IRPA Potential Scenarios Methodology	[redacted]	[redacted]	-	[redacted]
WP5 - General Support	[redacted]	[redacted]	-	[redacted]
WP6 - Witness and Interrogatory Support	[redacted]	-	[redacted]	[redacted]
Total	[redacted]	***$224,675***	***$26,500***	***$251, 175***

As in previous engagements with EGI, we recommend EGI consider the total proposed cost as a budget ceiling; we propose undertaking work on an hourly basis with a monthly billing cycle for fees incurred in the preceding month.

Project: IRP Model Updates
Re: Proposed amendments to project scope and budget cap per prioritization discussion from May 25, 2023
Submitted to: Chris Ripley, Whitney Wong, Geoff Chung, Kurtis Lubbers
Date Submitted: June 8, 2023, **with an update from August 14, 2023, in Section 4**

1 Purpose

This project purposefully started with a broad scope to enable an agile approach to meeting EGI's needs as the project has progressed and we have encountered evolving priorities based on the scope items that we have delivered over time. Since we are starting to approach the budget cap, PG met with EGI on May 25 to discuss which scope items should be prioritized and how the budget cap might need to be adjusted to account for changes throughout project delivery. This memo captures the outcomes of this discussion and serves as the basis for amending the existing project purchase order (PO).

The remainder of this memo is structured as follows:

- Section 2 outlines the scope items that should be prioritized under the budget cap.
- Section 3 outlines the scope items that, based on our discussions and collective decisions throughout the project, should be parked and not completed under the budget cap.
- Section 4, uses our scope and budget performance to date to forecast where this project is expected to land in relation to the existing budget cap, and proposes an amendment to the budget cap.

2 Items Prioritized under the Budget Cap

We plan to complete the following scope items (that are not already listed as In Progress in our project management system) to ensure key IRP model inputs and scenario modelling approaches are addressed before the end of the current contract.

Scope Item	Comments
WP1 – Reference Case Updates	
Check for updated scenario assumptions in the EGI forecast	N/A
Confirm whether any large customers were removed	N/A
Extend forecast to 2063	N/A
Reflect EGI's adjusted account forecast	N/A
Update the demolition rate to 0%	N/A

Update segmentation mapping to match DOE sectors	N/A
Ongoing ad-hoc vetting & correction of Unit Energy Consumption (UEC) assumptions (these are based on UECs from the 2019 APS – the Navigator model multiplies UECs by fuel share, saturation, and units for each combination of end use and segment to calculate annual consumption)	This refers to checking whether UECs behave rationally from one year to the next and implementing fixes where they do not (we have found some instances of this in individual IRPAs – the issue stems from UECs in the last Achievable Potential Study). More fulsome vetting of UECs would be required via separate project scope (e.g., for preparing inputs for or processing results of the upcoming Achievable Potential Study).
WP2 – Load Shape Recalibration	
Align peak hourly customer flows to DOE model assumptions	N/A
Stretch existing load shapes to better match DOE calibration targets	N/A
Assess how certain measures impact base versus heating loads	PG plans to check whether any hours are left over from its work with a load shape expert for stretching existing load shapes to better match DOE calibration targets; PG plans to use any such leftover hours to tackle these measure-specific items and will propose alternative options to EGI if no hours are left over at the completion of the load shape stretching tasks
Assess measures that impact base temperature & convert annual to peak savings on this basis (variable conversion factor)	
WP3 – ETEE Measure Assumption Updates[1]	
Verification: remove peak savings from adaptive thermostats	N/A
Verification: zero out costs for measures that do not contribute to peak savings in the ETEE scenario	N/A
WP4 – IRPA Potential Scenarios Methodology	
Determine whether technical potential plus derating factors is the most appropriate approach to use for the IRP model	This entails revisiting our discussions and collective decisions about derating factors (applied by EGI as post-model adjustments) and verifying that these are still appropriate in light of the updated scenario runs
Produce a DSM BAU baseline	N/A
Review negative savings instances & develop methods for interpreting such results	Running the existing franchise-area IRP Model produces instances where savings for certain measures in some segments, end uses, and years are negative; this scope item plans to check whether these instances are reasonable and how they should be interpreted

[1] A scope item for better aligning measure savings with EGI's percentage savings is already ongoing in PG's project management system and will be completed under the budget cap.

Should Budget Solver optimize for peak or annual savings?	N/A
WP5 - General	
Develop a summary report that describes model inputs, methods, and results	N/A

3 Items Deprioritized under the Budget Cap

Based on our project experience, discussions, and collective decisions to date, we plan to park the following scope items without addressing them under the budget cap.

Scope Item	Comments
WP1 – Reference Case Updates	
N/A	N/A
WP3 – ETEE Measure Assumption Updates	
Characterize an electric heat pump measure	We collectively decided to park this scope item in favor of just keeping the hybrid heading measure that PG has already characterized in the DSM BAU and ETEE measure assumptions
Characterize early replacement measures	We collectively decided to park this scope item
WP4 – IRPA Potential Scenarios Methodology	
Consider what drivers we would alter to conduct a stochastic analysis	Given the importance of other scope items, we plan to park this for now
Determine the difference between achievable and economic potential for ETEE scenarios	Give EGI's thoughtful approach to derating factors, we plan to focus on the derating factors rather than differences between economic and achievable potential
Natively implement the DCF+ test in Navigator	Since the specifications of the DCF+ test are still in flux and this scope item requires code modifications in Navigator, we plan to park this for now
Develop appropriate Net To Gross ratios and apply these to prepare gross budgets (the current IRP Model bases its measure savings on the 2019 APS which provided data in net terms, so PG grosses up the budgets from the model results to reflect actually expected program spending)	PG has been a taker of NTG data from EGI's DSM BAU plans and its DCF+ assumptions. Since more significant alternative sources of uncertainty exist, we plan to park this item until more reliable NTG data is available from the ETEE pilots.

4 Budget Performance

Based on actual project performance to date (completed scope percentage versus percentage of budget cap spent), our project management system forecasts that we will exceed the current maximum budget cap by $31,211 if we complete the items proposed under Section 1. The following key factors have contributed to this forecast overage:

- Identification and implementation of fundamental method items that were not part of the planned scope (e.g., switching the calibration approach for the model and downstream IRPA analyses).
- Delays in receiving required input data.
- Additional collective effort for exploring and overcoming input data quality issues.

We recognize that this project represents a collaborative effort between EGI and PG and that its agile nature necessarily means some of the key factors that have contributed to the forecast overage were difficult to foresee during the planning stages. As such, we propose to split the forecast overage as follows: PG would be responsible for $7,803 (25%) of the overage and would request EGI to increase its budget cap for the project by the remaining $23,408.

August 14 Update:

After stretching existing load shapes to better match DOE calibration targets, PG does not have leftover hours with its external load shape expert (as contemplated in Section 2) to examine how certain measures impact balance temperatures and shift load shapes under Work Package 2. This is due to two factors:

- **EGI requested PG to use 8 additional weather stations (for a total of 13 weather stations, compared to the 5 weather stations used for the original IRP Model) to calculate comparisons between historical average and design day weather**
- **The selected Environment and Climate Change Canada weather stations contain significant periods of missing data, requiring us to selectively replace the missing data points**

PG developed computer code to automatically access and process the weather data to maximize efficiency, but this was unable to fully compensate for the above two factors.

As such, $4,500 of additional time from PG's external load shape expert is required to examine how certain measures impact balance temperatures and shift load shapes. We propose to add this additional cost to the requested budget cap increase: the original $23,408 to account for budget overage, plus $4,500 for additional time from the load shape expert, for a total of $27,908.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

C1 Page 15, Table 1 and PollutionProbe_IR_AppendixA_IRPOCDA_20240814

Question(s):

a) Please reconcile the EB-2022-0200 Exhibit I.9.1-PP-40d response (per attachment noted above) with Table 1.

b) Please confirm that the balance in the Enbridge Gas IRP Capital Cost Deferral Account (Account No. 179-386) is still zero. If that is incorrect, please provide the current values and when they were journaled into the account.

Response:

a) The referenced EB-2022-0200 Exhibit I.9.1-PP-40 part d) response refers to costs associated with the 2022 balance of the Enbridge Gas IRP Operating Cost Deferral Account and would have been cleared and disposed of in the 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances[1].

   The costs included within Exhibit E, Tab 1, page 15, Table 1, refers to costs associated with the 2023 balance of the Enbridge Gas IRP Operating Cost Deferral Account.

b) Confirmed.

[1] EB-2023-0092.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

The East Kingston Creekford Rd Reinforcement project was a planned $24.3 million capital reinforcement for 2024. Enbridge Gas's Asset Management Plan (AMP) included this investment in the 2024 – 2028 Rebasing application6. The proposed facility project submitted in the AMP was a replacement of the entire existing NPS 6 pipeline from Westbrook check measurement station (CMS) to the Woodbine town boarder station (TBS) to account for forecasted growth, and to address class location and depth of cover issues which exist on the current Kingston Lateral. [EB-2023-0092 Exhibit C, Tab 1, Page 20, including footnote 6 - EB-2022-0200, Exhibit 2.6.2 Appendix A, p. 25 of 59.]

Question(s):

a) Please confirm that the CNG IRP alternative is to replace a project that was planned for 2024 in the Enbridge AMP and as presented in EB-2022-0200 (Enbridge 2024-2028 Rebasing period). If incorrect, please explain.

b) Please provide any OEB approvals from EB-2022-0200 related to this project and/or the 2024 Capital envelope for which this project was identified.

c) Please explain why Enbridge is describing the East Kingston Creekford Rd project as a Reinforcement project, when the purpose (as noted above) is a replacement of the existing pipeline.

Response:

a) Confirmed. For clarity, two IRP alternatives, CNG in conjunction with the contract customer firm demand turnback, were implemented to defer the need for the proposed East Kingston Creekford Reinforcement project.

b) This project was included in the 2023-2032 Asset Management Plan – Appendix A[1] as part of the 2024 Phase 1 Rebasing application, which was not approved as filed. The OEB approved a capital budget in the 2024 Phase 1 Rebasing application that

[1] EB-2022-0200, Exhibit 2, Tab 6, Schedule 2, Appendix A, p.25.

included a reduction to the overall capital budget and directed Enbridge Gas to report on the implementation of that reduction as part of the Phase 3 Rebasing application. The project, with an updated in-service date of 2027, was included in the Capital Update filed in the 2024 Phase 1 Rebasing application[2].

c) As noted in Enbridge Gas's 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances[3], the proposed project addressed three project drivers, inclusive of increased forecasted demands driven by growth, depth of cover and class location. While the existing NPS 6 pipeline needs to be replaced, this is classified as a reinforcement project as the facility scope of the NPS 8 pipeline installation provides incremental capacity to meet the growth demands on the system.

[2] EB-2022-0200, Exhibit 2, Tab 5, Schedule 4, p.22.
[3] EB-2022-0092, Exhibit C, Tab 1, p.21

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Enbridge Gas engaged Posterity to assess the ETEE potential for the Kingston project service area to understand if conservation could reduce demands and reduce, defer or eliminate the facility infrastructure needed. [EB-2023-0092 Exhibit C, Tab 1, Page 24]

Question(s):

Please provide a copy of the Posterity Report.

Response:

Please see Attachment 1.

IRP Analysis Project
Kingston System Reinforcement Project Modelling Findings

Project: Integrated Resource Planning Alternative Analysis (IRPA Analysis)
Re: Kingston System Reinforcement Project (Kingston)
Submitted by: Posterity Group
Date: August 24, 2022

This memo presents information about the potential to reduce natural gas peak hour demand in the context of the Kingston System Reinforcement Project (Kingston), including the potential peak hour demand reduction, in m^3/hr, by winter 2027/2028 and 2042/2043, and the associated costs. The scope of the analysis focuses on demand side management (DSM) IRPAs (including energy efficiency and demand response measures). The analysis was performed using data from the current version of the Posterity 'mirror model' of the 2019 Achievable Potential Study (APS), which was centered around DSM and is being used as a proxy to demonstrate ETEE potential for the system of need.

This memo focuses on existing and future general service customers and the potential for these customers to reduce peak hour demand during the forecast period.

1 Profile of Customers Included in Analysis

The analysis focused on a subset of customers in Kingston. Only general service customers are included in this analysis; contract customers are not included.

1. The following sectors and rate classes were included in the scope of the analysis:
   - Residential: 1, 10
   - Commercial: 1, 10
   - Industrial: 1, 10
2. The reference peak hour demand is forecasted to increase from 34,542 m^3/hr in 2021 to 37,090 m^3/hr by 2027 and 40,283 m^3/hr by 2042.
   - The total peak hour demand in 2027 is expected to be 37,090 m^3/hr, comprised of 1,686 m^3/hr in the industrial sector, 11,035 m^3/hr in the commercial sector, and 24,369 m^3/hr in the residential sector.
   - The total peak hour demand in 2042 is expected to be 40,283 m^3/hr, comprised of 1,763 m^3/hr in the industrial sector, 12,548 m^3/hr in the commercial sector, and 25,972 m^3/hr in the residential sector.

2 Peak Hour Reduction and Cost

This analysis was intended to answer two research questions:

1. Using data from the current version of the Posterity 'mirror model' of the 2019 APS, what is the maximum peak hour reduction potential?
    - Five years from now, in the winter of 2027/2028,[1] peak hour reduction potential from DSM is estimated to be 4,613 m^3/hr, which would be a 12.4 percent reduction in the total hourly peak demand.
    - Twenty years from now in the winter of 2042/2043,[2] peak hour reduction potential from DSM is estimated to be approximately 6,950 m^3/hr, which would be a 17.3 percent reduction in the total hourly peak demand.
2. How much would the peak hour reduction cost?
    - The total gross cost of the 4,613 m^3/hr of potential reduction that could be obtained by winter 2027/2028 would be $28,080,570; or an average gross cost of $6,087 per m^3/hr reduction. [3]
    - By the winter of 2042/2043, the total gross cost of the 6,950 m^3/hr of potential reduction would be $53,198,475; or an average gross cost of approximately $7,654 per m^3/hr reduction.

3 Most Impactful Sectors and End Uses

In addition to the preliminary answers to these two questions, the following key observations were made for the winter of 2027/2028:

- The residential sector accounts for 94 percent of the peak hour reduction while representing only 66 percent of the total peak hour consumption before any savings. The main reason for this discrepancy is that measures in the residential sector were predominantly space heating measures:
    - Space heating measures account for 96 percent of peak hour reductions and the residential sector accounts for 98 percent of the space heating reduction.
    - Space heating measures were more likely to pass the TRC test, including in the residential sector.

[1] Winter 2027/2028 savings and costs are represented by savings and costs for 2027 in the model to reflect the measures included before winter 2027/2028.
[2] Winter 2042/2043 savings and costs are represented by savings and costs for 2042 in the model to reflect the measures included before winter 2042/2043.
[3] A Net-to-Gross ratio of 75 percent was used to estimate the gross costs of the program. The total gross costs presented do not include fixed portfolio overhead costs.

  - A few key residential measures made up the majority of the total peak hour reductions: whole home building envelope in detached homes (30 percent), air sealing in detached homes (21 percent), and shifting heating off peak (16 percent).
- The commercial sector makes up 29 percent of the total peak hour consumption but only accounts for 2 percent of the peak hour reductions. This effect is due to the dominance of the few residential space heating measures mentioned above over all other measures:
  - 92 percent of commercial peak hour reductions come from space heating.
  - Within space heating, 32 commercial measures pass the TRC, which is more than the 20 residential space heating measures that pass the TRC. individual commercial measure accounted for more than 1 percent of the total peak hour reduction, compared to residential where only 3 measures accounted for 67 percent of the total peak hour reduction.

The following observations were made for the winter of 2042/2043:

- By 2042, the commercial sector accounts for a greater proportion of all-sector savings than it did in 2027, but still has less savings than in the residential sector.
  - Commercial and residential space heating measures account for 11 percent and 85 percent, respectively, of the total hourly peak savings.
  - The growth in commercial sector savings is in part due to the slight increase in the commercial sector peak hourly demand. By 2042, the commercial sector makes up 31 percent of the total peak hourly demand and residential makes up 64 percent (compared to 29 percent in commercial and 66 percent in residential in 2027).
  - The growth in commercial sector savings is also due to the introduction of the Super High Performance Glazing measure which accounts for 73 percent of hourly peak demand savings in the commercial sector by 2042. This measure did not pass the TRC test in 2027.
  - The same three dominant residential space heating measures from 2027 plus the heat recovery ventilator measures make up the majority (67 percent) of residential space heating savings in 2042, but they make up less of the overall savings (only 57 percent) because of the increase in savings from other residential and commercial measures.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

The East Kingston Creekford Rd Reinforcement project was a planned $24.3 million capital reinforcement. Enbridge Gas determined that this project could be deferred by implementing a supply side IRP alternative in the form of CNG beginning in 2022. [Exhibit C Tab 1 Page 19]

Question(s):

a) Please confirm that the Enbridge did not file an IRP application for the East Kingston Creekford Rd Reinforcement project and has not previously received OEB approval for this IRP project. If not correct, please provide the details.

b) Was the East Kingston Creekford Rd Project the name of the original Capital project in Enbridge's Asset Management Plan, or just the name of the IRP Alternative? If there was a different name for the Capital project, please provide it.

c) Please provide the most recent Asset Management Plan references filed with the OEB that includes the East Kingston Creekford Rd Project (or alternate name if applicable) that was deferred.

d) Please provide the first Enbridge AMP version reference that includes the East Kingston Creekford Rd Reinforcement project. If the first AMP reference to the Reinforcement has not been filed with the OEB, please file the related pages pertaining to the Reinforcement.

e) Please provide the most recent Enbridge AMP materials filed with the OEB that includes the East Kingston Creekford Rd Reinforcement project planned at a cost of $24.3 million.

f) Is the East Kingston Creekford Rd Reinforcement project in the most current version of the Enbridge AMP? If yes, please provide the refences if already available on the OEB record or provide the relevant documentation if not already filed.

g) Please explain when the East Kingston Creekford Rd Reinforcement project is deferred until and the analysis (report, presentation or other information) supporting the deferral period.

Response:

a) Confirmed. Enbridge Gas did not file an IRP application as the cost was below the $2 million threshold.

b) The full name of the East Kingston Creekford Rd Project in Enbridge's Asset Management Plan is "SRP_LUG East_Kingston_Creekford Rd_ Reinforcement _ NPS8_6200m_6895kPa".

c) Please see EB-2020-0091 – Enbridge Gas Asset Management Plan Addendum – 2024, Appendix B - IRP (Updated), page 14 of 172, filed October 31, 2023.

d) Please see EB-2022-0200, Exhibit 2, Tab 6, Schedule 2, Appendix A, page 25 of 59, filed October 31, 2022.

e) Please see response at part c).

f) and g)

Since the filing of the 2023-2032 AMP in the fall of 2022, demand assumptions have been updated which have resulted in changes to system reinforcement projects. The East Kingston Creekford Rd Reinforcement as originally scoped included project drivers such as growth reinforcement, class location and depth of cover. This work is currently being re-evaluated given the deferral of the reinforcement project to determine the scope and timing required to address the class location and depth of cover issues. These changes will be reflected in the 2025-2034 AMP to be filed in fall 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Exhibit D, Tab 1, Attachment 1

Question(s):

Please provide a copy of the RFP and Highwood agreement for the EGI Fugitive Emissions Measurement Report.

Response:

A copy of the Highwood Emissions Management contract and the RFP for EGI's Fugitive Emissions Measurement Plan Project have been included as Attachment 1 and Attachment 2, respectively.

50 Keil Drive North Box 2001
Chatham ON N7M 5M1

Peter Mussio, Manager, Carbon Strategy
Tel: 519-437-6988
Email: peter.mussio@enbridge.com

October 6, 2023

HIGHWOOD EMISSIONS MANAGEMENT INC.
Suite 600 – 441 5th Avenue SW
Calgary Alberta T2P 2V1

RE: Consulting Agreement with Enbridge Gas Inc.

Attached please find for signature our Consulting Agreement. Kindly arrange to have the Agreement and the attached Schedule signed. Please ensure you read and understand all of the terms and conditions of the Agreement.

We will also require the following:

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

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

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

Sincerely,

Peter Mussio
Manager, Carbon Strategy

Encls.

CONSULTING AGREEMENT

THIS AGREEMENT made effective October 6, 2023.

B E T W E E N:

ENBRIDGE GAS INC.
("Enbridge")

- and -

HIGHWOOD EMISSIONS MANAGEMENT INC.
(the "Consultant")

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

1. **Scope of Services**

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

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

2. **Compensation**

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

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

Where the Consultant is a non-resident of Canada for purposes of the Income Tax Act (Canada) (the "ITA"), with respect to the invoice or statement of Fees issued pursuant to any schedule, the Consultant will identify the location where the Services are provided, separate Services performed in Canada from Services performed outside of Canada, identify the number of days Services were performed in Canada (including travel days to/from Canada) and, for Services performed in Canada, identify the physical location, indicating city and province, where such Services were performed. Where the non-resident

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

3. **Term**

Subject to earlier termination as provided for herein, the term of this Agreement shall commence on the day set forth above and expire on December 31, 2025 (hereinafter the "Term").

4. **Termination**

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

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

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

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

5. **Facilities**

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

6. **Reimbursement for Expenses**

In addition to the payments to be made pursuant to Section 2 hereof, Enbridge shall reimburse the Consultant for all reasonable expenses properly incurred by the Consultant in connection with the Services provided to Enbridge hereunder and that have been pre-approved by Enbridge in writing, including, without limitation, reasonable travel and other costs and expenses in connection therewith. Such pre-approved reasonable expenses incurred by the Consultant in rendering Services shall be reimbursed by Enbridge net of GST/HST. GST/HST shall be charged, where applicable, by the Consultant on the expenses incurred, net of the input tax credits/reimbursements for GST/HST claimed by the Consultant. Concurrently with its delivery of invoices to Enbridge as contemplated by Section 2 hereof, the Consultant shall submit to Enbridge invoices and statements setting out in reasonable detail the nature and amount of the expenses or costs incurred by the Consultant for which the Consultant claims reimbursement, and Enbridge shall within sixty (60) days of the receipt of such invoices and statements reimburse the Consultant for all approved invoiced expenses and costs. The Consultant shall provide to Enbridge copies of all documentation in support of invoiced expenses as Enbridge may request from time to time during the Term hereof.

7. **Independent Contractor**

Notwithstanding anything to the contrary herein contained, the Consultant shall not, for any purpose, be or be deemed to be an employee of Enbridge during the Term or at any time during which the Services described in Section 1 hereof are provided to Enbridge nor shall anything in this Agreement create or be construed for any purpose as creating any relationship between Enbridge and the Consultant of employer and employee. Except as expressly provided herein, Enbridge shall not be liable to contribute to any employee benefit or pension plan or pay premiums for any policy or form of insurance whatsoever on behalf of the Consultant nor to pay any amounts or premiums on its behalf in respect of the Canada Pension Plan, Ontario Health Insurance Plan, Workplace Safety and Insurance Board or Employment Insurance, nor to deduct or withhold from source any amount from amounts payable by Enbridge to the Consultant hereunder in respect of any income tax obligation or liability payable by the Consultant to the Canada Revenue Agency. The Consultant agrees to indemnify and hold Enbridge harmless from and against any order, penalty, interest or tax that may be assessed or levied against Enbridge as a result of the failure or delay of the Consultant to file any return or information required to be filed by the Consultant by any law, ordinance or regulation relating to the Services performed by the Consultant herein.

8. **Confidential Information and Personal Information**

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

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

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

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

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

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

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

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

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

(e) The Consultant acknowledges and agrees that Enbridge would be irreparably harmed if any provision of this Agreement is not performed by the Consultant in accordance with its terms. Accordingly, Enbridge shall be entitled to an injunction or injunctions to prevent breaches of any of the provisions of this Agreement and may specifically enforce such provisions by an action instituted in a court having jurisdiction. These specific remedies are in addition to any other remedy to which Enbridge may be entitled at law or equity.

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

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

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

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

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

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

9. **Indemnification**

The Consultant hereby agrees to and shall:

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

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

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

10. **Work Product**

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

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

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

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

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

11. **Representations and Warranties**

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

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

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

12. **Subcontractors**

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

13. **Insurance**

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

(a) Commercial General Liability insurance having a minimum inclusive coverage limit, including personal injury and property damage, of at least Five Million Dollars ($5,000,000) per occurrence. Enbridge Gas Inc. must be listed as the certificate holder and be added as an additional insured in the insurance policy, which should be extended to cover contractual liability, products/completed operations liability, owners'/ contractors' protective liability and must also contain a cross liability clause;

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

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

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

The Consultant shall forthwith after entering into this Agreement, and from time to time thereafter at the request of Enbridge, furnish to Enbridge a memorandum of insurance or an insurance certificate setting out the terms and conditions of each policy of insurance (all such policies of insurance being hereinafter described as the "Insurance Policies") maintained by the Consultant in order to satisfy the requirements of this section. At any time and from time to time at the request of Enbridge, the Consultant shall furnish Enbridge with one or more duly completed insurance certificates in the form requested by Enbridge to evidence the details of all the Insurance Policies. The Insurance Policies shall be arranged with insurers acceptable to Enbridge, acting reasonably, and shall contain such terms and conditions as are reasonably acceptable to Enbridge. The Consultant shall not cancel, terminate or materially alter the terms of any of the Insurance Policies without giving thirty (30) days prior notice in writing to Enbridge. The Consultant shall cause or arrange for any of its insurers under any one or more of the Insurance Policies to oblige itself contractually in writing to Enbridge to provide thirty (30) days prior notice in writing before cancelling, terminating or materially altering the Insurance Policies under which it is an insurer.

14. **Compliance with Laws**

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

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

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

15. **Waiver**

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

16. **Notice**

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

If to Enbridge:

> ENBRIDGE GAS INC.
> 50 Keil Drive North Box 2001
> Chatham ON N7M 5M1
> Attention: Peter Mussio, Manager, Carbon Strategy
> Phone: 519-437-6988
> Email: peter.mussio@enbridge.com
>
> With a copy to: Law Department
> Email: egilawcontracts@enbridge.com

If to the Consultant:

> HIGHWOOD EMISSIONS MANAGEMENT INC.
> Suite 600 – 441 5th Avenue SW
> Calgary Alberta T2P 2V1
> Attention: Nick Fane, Director of Revenue
> Phone: 250-215-6689 Ext.
> Email: nick.fane@highwoodemissions.com

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

17. **Interpretation**

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

18. **Assignment**

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

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

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

20. **Time of Essence**

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

21. **Survival**

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

22. **Further Assurances**

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

23. **Entire Agreement**

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

24. **Audit**

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

25. **Enbridge Policies**

In the delivery of Services under this Agreement, the Consultant shall comply with, and shall cause all other parties acting on the Consultant's behalf to comply with, all policies, processes, and procedures of Enbridge: (i) made available from time to time on the https://www.enbridge.com/work-with-enbridge/doing-business-with-enbridge/policies website (which URL may change from time to time at Enbridge's discretion), or (ii) otherwise communicated to the Consultant in writing ("Company Policies") as each such Company Policy may be amended from time to time. If requested by Enbridge, the Consultant will attend and ensure all other parties acting on the Consultant's behalf attend training on Company Policies. The Consultant acknowledges that failure to comply with Company Policies will constitute a material breach of this Agreement which will allow Enbridge to take immediate remedial steps, including termination.

26. **ISNetworld Requirement**

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

27. **Counterparts and Execution**

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

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

HIGHWOOD EMISSIONS MANAGEMENT INC.	**ENBRIDGE GAS INC.**
By: Jessica Shumlich	By: Peter Mussio Peter Mussio (Oct 11, 2023 13:25 EDT)
Name: Jessica Shumlich	Name: Peter Mussio
Title: CEO	Title: Manager, Carbon Strategy
By: ______________	By: ______________
Name:	Name: * *
Title:	Title: *
(Please print name and title of Signing Officer)	

Witness: ______________

Name:

(Witness required if Contractor is a Sole Proprietor)

SCHEDULE A

TO THE CONSULTING AGREEMENT BETWEEN
ENBRIDGE GAS INC. AND HIGHWOOD EMISSIONS MANAGEMENT INC.
Dated October 6, 2023

This Schedule is made under the above referenced consulting agreement (the "Agreement") between ENBRIDGE GAS INC. ("Enbridge") and HIGHWOOD EMISSIONS MANAGEMENT INC. (the "Consultant").

1. **SCOPE OF SERVICES**

The Consultant will undertake the following Services:

Preparation of a comprehensive study that includes:
(1) assessment of Enbridge's fugitive emission inventory;
(2) review of Enbridge's current leak survey practices for distribution, storage, and transmission;
(3) review of different methodologies to calculate fugitive emissions;
(4) comprehensive review/comparison of different detection technologies and cost of deployment;
(5) recommendations to be submitted to the Ontario Energy Board; and
(6) road map for implementation plan.

A description of Services and key personnel to be provided by the Consultant is set forth in the proposal dated September 1, 2023 prepared by the Consultant, which is attached as Attachment 1 to this Schedule (the "Proposal") and incorporated by reference herein. In the event of a conflict between the terms and conditions set out in the Proposal and those set out in this Agreement, the terms and conditions in this Agreement (including this Schedule) will govern and take precedence.

2. **DELIVERABLES**

The Consultant will provide the following deliverables:

- A kick-off meeting with key stakeholders from Enbridge and bi-weekly updates to Enbridge through progress update meetings/reports.

- Review the green house gas (GHG) emissions inventory working files, assess source contributions and missing sources, provide current methodology summary and current uncertainty analyses.

- Conduct technology and methodology review, including identification of commercially available technologies, detailed review of the technologies, cost and benefit analyses, and associated uncertainty analyses.

- Develop a draft report that includes all the required analyses outlined in the Scope of Work section.

- Present the results to key stakeholders at Enbridge for review and approval. Generate a final report with feedback and changes.

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

This Schedule shall be effective as of October 6, 2023 and expire June 30, 2024, or such other date as the parties may mutually agree in writing.

4. **KEY PERSONNEL**

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

Thomas Fox, President, Expert Witness

5. **FEES AND PAYMENT TERMS**

[redacted]

Expenses: N/A

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

Fees are payable by Enbridge within sixty (60) days of receipt from the Consultant of an appropriate invoice setting out in reasonable detail the nature of the services provided.

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Dated as of October 6, 2023.

HIGHWOOD EMISSIONS MANAGEMENT INC.	**ENBRIDGE GAS INC.**
By: Jessica Shumlich	By: Peter Mussio Peter Mussio (Oct 11, 2023 13:25 EDT)
Name: Jessica Shumlich	Name: Peter Mussio
Title: CEO	Title: Manager, Carbon Strategy
By: ______________	By: ______________
Name:	Name: * *
Title:	Title: *
(Please print name and title of Signing Officer)	

Witness: ______________

Name:

(Witness required if Contractor is a Sole Proprietor)

ATTACHMENT 1, Proposal is attached at the following pages.

RFP Technical Proposal

OEB Fugitive Measurement Requirements Project

Date
2023-09-01

Focus
Proposal for Enbridge OEB Fugitive Measurement Requirement Project RFP dated 2023/08/11

Team
Thomas Fox, President
Paul Ashford, VP Consulting
Heather Isidoro, Senior Consultant, Voluntary Initiatives
Maddy Strange, Reconciliation Technologist
Brendan Moorhouse, Fugitive Emissions Lead
Nick Fane, Director of Revenue

Prepared for

ENBRIDGE
Enbridge Inc.

September 1, 2023

Enbridge Gas Inc., Carbon Strategy
Ge Li, Carbon Strategy, Analyst, Enbridge
Peter Mussio, Manager Environment, Union Gas
Ainslie Murdock, Environmentalist, Union Gas

Re: OEB Fugitive Measurement Requirement Project

Highwood Emissions Management Inc. (Highwood) is pleased to provide Enbridge Gas Inc. (Enbridge) with this proposal in response to the RFP provided on August 11, 2023, for support in fulfilling the commitment Enbridge Gas Distribution and Storage (GDS), a division of Enbridge, made to the Ontario Energy Board (OEB) to investigate fugitive emission sources and their contributions towards Unaccounted For Gases (UFGs).

This proposal outlines the processes through which Highwood will investigate technologies and methodologies for the measurement of fugitive emissions within the GDS transmission, distribution, and storage assets of interest. Highwood will provide a comprehensive review of fugitive emissions quantification methodologies and measurement technologies, including those specifically applicable to GDS operations, and make recommendations for an implementation plan to accurately quantify fugitive emissions. This report is anticipated to be presented to the OEB for considerations and determination in the 2024 deferral and variance account proceeding and will support future efforts to assess fugitive emissions sources and identify appropriate mitigation efforts.

In this proposal we highlight several key differentiators that set Highwood apart from other service providers in this space. Due to Highwood's extensive background in leak detection technology validation, coupled with expertise in fugitive emissions inventories and calculations as well as methane measurement protocols, GDS stands to benefit from a streamlined engagement with Highwood. Once Highwood is provided with the existing fugitive emissions inventory, along with any results or outcomes from prior LDAR campaigns, Highwood can execute on this project with limited hands-on involvement from Enbridge, alleviating resource constraints and improving operational efficiency.

Thank you for considering our proposal. We welcome any questions or concerns. Note that we are flexible, and that this proposal could be scaled back or expanded to align with GDS's goals and budget. We look forward to the prospect of working with GDS on this important project.

Sincerely,

Paul Ashford, P. Eng.
VP of Consulting
Highwood Emissions Management Inc.
Suite 600 – 441 5th Avenue SW Calgary, Alberta, Canada, T2P 2V1
paul@highwoodemissions.com

Table of Contents

Contents

Background ... ***4***

About Highwood ... ***5***

Overview ... 5

Our Approach ... 5

The Highwood Advantage ... 6

Scope of Work ... ***8***

Project Objectives ... 8

Highwood Team Key Project Members ... 8

Scope 1: Evaluation of Enbridge's fugitive emissions inventory ... 9

Objectives ... 9

Approach and Work Plan ... 9

Scope 2: Technology and Measurement Methodology Evaluation ... 11

Objectives ... 11

Approach and Work Plan ... 11

Scope 3: Recommendation and Implementation Plan ... 13

Objectives ... 13

Approach and Work Plan ... 13

Scope 4: Preparation of the Deliverable ... 15

Timeline ... ***16***

Cost Estimate ... ***17***

Invoicing Schedule ... ***17***

Experience and Qualifications ... ***18***

Expert Witness Experience ... 19

Our Experts ... 20

Background

In the Decision on Settlement Proposal EB-2022-0200 published on August 17, 2023, the Ontario Energy Board (OEB) accepted Enbridge Gas Inc's (GDS) partial settlement proposal, pending the investigation of fugitive emissions within the GDS assets located in Ontario. As part of a rebasing settlement between GDS and the OEB, GDS has committed to complete an investigation to identify and study measurement and reporting strategies related to fugitive emissions, a component of total Unaccounted For Gas (UFG) volumes. This investigation is required as part of GDS's application to change its natural gas rates and other charges, at the start of 2024.

An improved fugitive emissions measurement plan can enable GDS to more accurately predict UFG volumes, which will impact consumer gas rate setting, and decrease the variance observed between the expected and actual volumes. Decreasing the variance between these gas volumes will impact costs and credits, both to GDS, and to the rate payers themselves. A robust investigation plan will be prepared for submission to the regulator, addressing the following three goals:

1. Confirming the volume of fugitive emissions,
2. Determining if recent UFG increases could be due to fugitive emissions,
3. Attempting to locate specific fugitive sources that can be mitigated.

This proposal outlines how Highwood will assist GDS in the research, development, and scientific verification of the investigation plan for submission to the OEB.

About Highwood

Overview

Highwood Emissions Management Inc. is based in Calgary, Alberta. Working with industry, government, and innovators, we leverage data, analytics, knowledge, and experience to optimize GHG emissions management. Our mission is to collaborate, innovate, and educate the path to a world with effective and affordable emissions management solutions.

This project will be led by Heather Isidoro (Senior Consultant, Voluntary Initiatives), with direct oversight from Paul Ashford (VP and consulting) and technical guidance from Dr. Thomas Fox (President & Director of Innovation). Additional support will be drawn from several of the key Highwood staff identified below. This project will require an interdisciplinary team because it requires a combination of individuals skilled in data science and support from engineers to interpret results. One of our guiding principles is that effective decision-making in emissions management lies at the intersection of knowledge and data. Highwood's services have led to several impactful projects for our clients. Our team is uniquely suited to combine leading analytical methods with detailed, nuanced interpretations from field experts. This project requires expertise at the intersection of engineering, oil and gas, and academia, which Highwood is uniquely suited to offer. The below sections describe what sets Highwood apart for this work.

Our Approach

Our approach to consulting is centered around collaboration, efficiency, strong communication, and effective project management. We believe that by working closely with our clients, we can achieve better results and deliver exceptional value.

Good communication is a cornerstone of our approach. Our team takes the time to understand the unique needs and challenges of each client. We understand the importance of regular check-ins and immediate updates on changes. As such, we leverage a robust project management framework that ensures we stay on track and keep our clients informed every step of the way. Our team will be available for regular check-ins to review progress, address any concerns, and make sure that everyone is aligned on the goals and objectives of the project.

Highwood is committed to building longevity in expertise for our clients. Our goal is not just to deliver great results today, but to also build long-term capacity and relationships that deliver value for years to come. Our team has the expertise, experience, and passion to make this a reality, and we are confident that our approach will set us apart from other consulting firms.

The Highwood Advantage

The Highwood team possesses an extensive background of analyzing leak detection technologies, expertise in working with fugitive emissions inventories, and conducting fugitive emission calculations with numerous clients. Highwood works at the cutting edge of emissions management science, engineering, and application. Highwood values continuous engagement with GDS and has included suggestions for feedback opportunities within this proposal. Compared to other companies in this space, Highwood offers several key differentiators relevant to the scope of this project:

- **LDAR-Sim:** is an open-source software tool invented and developed by Thomas Fox, President and Co-Founder of Highwood. It has gained prominence within the oil and gas industry and has been used for multiple regulatory approvals of alternative emissions detection technologies. LDAR-Sim is recognized by regulators across North America (e.g. the US Environmental Protection Agency (EPA) and the Colorado Department of Public Health and Environment (CDPHE)), industry groups (e.g. the American Petroleum Institute (API), Colorado Oil & Gas Association (COGA)), emission standards associations (e.g. MiQ), international investors (e.g. Oil and Gas Climate Initiative (OGCI)), and other diverse innovators in the emissions industry. Highwood is uniquely positioned to leverage and further develop the modelling power of LDAR-Sim through its internal team of LDAR-Sim experts, who have experience both running and developing the model. LDAR-Sim has been used on multiple projects for modeling pipeline fugitive emissions.
- **Technology Database**: Highwood has created and maintains a database of all commercial methane detection and measurement technologies. Currently, this database contains over 200 technologies across various deployment platforms, with different sensing principles. Many of these technologies are well suited for deployment on pipelines.
- **Experience working with regulatory bodies:** Highwood works closely with regulatory bodies and has extensive experience preparing the type of reports (scientifically backed) that they find rigorous and valid. Highwood has worked with the Pipeline and Hazardous Materials Safety Administration (the Federal body governing pipelines in the United States) to provide commentary and guidance on proposed new regulations surrounding leak detection.
- **Experience working with technology providers:** Highwood has worked with technology providers who specialize in leak detection on buried pipelines, providing competitive and market positioning analyses.
- **Experience working with pipeline operators:** Previous experience working with pipeline operators to find best suited technologies. Highwood has provided both qualitative and quantitative analyses to pipeline operators to identify technologies and leak detection work practices of highest effectiveness.
- **Industry Leading Authorship**: Highwood authored the 2022 report on Leak Detection Methods For Natural Gas Pipelines, which is the industry leading report on the detection of fugitive methane emissions from pipelines across the entire oil and gas value chain. We cover both legacy methods, such as visual surveys and handheld instruments, as well as a range of new, commercially available advanced solutions, such as drones, aircraft, and satellites. Additionally, Highwood has published a

novel report on 20+ voluntary emissions reduction initiatives available to the O&G industry, which can be downloaded here for free.

- **Methane Measurement Protocols:** Highwood has industry leading expertise in methane measurement protocols including those associated with voluntary initiatives such as OGMP 2.0, the Veritas Protocols, and MiQ. Highwood has delivered successful project to multiple clients who are OGMP 2.0 members, including evaluating adherence to LEVEL 4 requirements, technology options for both LEVEL 4 and LEVEL 5, and developing implementation plans which serve as a roadmap to achieving the Gold Standard of reporting. Highwood is the Technical Director of Veritas, a GTI Energy Differentiated Gas Measurement and Verification Initiative, which is developing methodologies for measurement informed emissions intensity. In addition, Highwood used LDAR-Sim to evaluate methane detection technologies and inform the MiQ Standard.
- **Custom internal consulting tools available only to Highwood's clients:** We have specialized tools for data management, quantification, and forecasting. Our proprietary 'Reduction Pathways' module helps companies build and optimize roadmap scenarios to net zero (or any target). These tools greatly lower manual work and therefore cost.
- **Broad experience with diverse clients:** Highwood is squarely focused on emissions and works with a long list of 90+ oil and gas clients, vendors, industry groups, regulators, and voluntary initiatives across all aspects of greenhouse gas emissions management. Some of our clients include Chevron, Shell, MiQ, GTI Energy, ATCO, Colorado Oil and Gas Association, Kairos Aerospace, SeekOps, Project Canary, Qube Technologies, Range Resources, ChampionX, TC Energy, and more.
- **Highwood's emissions and O&G expertise is unmatched:** The Highwood team possesses both leading academic expertise and decades of international oil and gas experience. The Highwood team consists of leading data scientists, software engineers, engineers and scientists of diverse backgrounds, and other specialists contributing to Highwood's comprehensive suite of technical services.
- **Recognition as global leaders in emissions management:** Our team has participated in numerous peer reviewed publications (e.g., here, here, and here) as well as teaching the world's foremost methane measurement technology course. We have worked for years at the interface of regulators, industry, and innovators to streamline the approval of novel methane technologies as an alternative to regulatory-approved methods. Highwood's President led ground-breaking work on technology approval that has been adopted by regulators across North America and endorsed by industry, innovators, academics, and regulators.
- **Drive for fostering education and innovation**: Highwood strives to work collaboratively with our clients to give them the knowledge, tools, and resources to succeed both for this project and in the future as they travel along their decarbonization journey.

Scope of Work

Project Objectives

Highwood will provide GDS with a comprehensive analysis of their current approach to measuring, calculating, and reporting fugitive emissions, which is a component of GDS's reported UFG volumes. Highwood will also evaluate the commercial options available for the measurement of these emissions and provide recommendations of feasible options to GDS. In addition, the successful deployment of an updated fugitive emissions monitoring plan will result in improved identification and localization of specific leak sources that can be mitigated, thus potentially lowering Enbridge's UFG volumes.

Key objectives for this project will include:

- Understanding the current approach used by GDS for reporting fugitive emissions and/or UFG to the regulator, including the measurement and calculation methodologies in use.
- A review of all available commercial technologies and methods that may be appropriate for use on GDS assets.
- A recommendation on the best measurement approaches for GDS to deploy, on a segment-by-segment basis. This recommendation may also provide benefits to other programs, including Enbridge's internal asset integrity management program.
- An implementation plan for Enbridge to plan and execute more effective technology deployments in line with the agreement with the Ontario Energy Board.
- Preparation of a report to be submitted by GDS to the OEB outlining the results of the evaluation and demonstrating GDS's plan to move forward in understanding the fugitive emissions component of GDS's UFG, in line with the rebasing settlement agreement.

Highwood Team Key Project Members

Key personnel that will be assigned on this project are listed below. Full bios for key and supporting project members are included in the "Our Experts" section. Additional Highwood experts may be called upon for support, as needed.

Thomas Fox (Ph.D., M.Sc., B.Sc.), President. *Executive direction and oversight*
Paul Ashford (B.A.Sc., P.Eng.), VP Consulting. *Project management oversight & senior support*
Heather Isidoro (P.Eng., MBA), Senior Consultant, Voluntary Initiatives. *Project Lead*
Maddy Strange (B.Sc., EPt.), Reconciliation Technologist. *Main contributor*
Antonio Monisit (M.Sc., B.Sc.), Differentiated Gas Technologist. *Support – Gas certification*
Brendan Moorhouse (B.Sc.), Fugitive Emissions Lead. *Support – Measurement technologies*

Scope 1: Evaluation of Enbridge's fugitive emissions inventory

Objectives

1. To assess and review the existing inventory of GDS's fugitive emissions by segment (Distribution, Transmission, Storage), including an analysis of the calculation methodologies which are currently in use, as well as data management practices.
2. To assess and review Enbridge's current practices for leak detection on the GDS system (including transmission).
3. To provide an overview of the calculation options which are available and appropriate for GDS to calculate their fugitive emissions, at different levels of granularity and accuracy.

Scope 1 encompasses 1, 2, and 3 from the RFP objectives.

Approach and Work Plan

Task 1.1: Review of fugitive emissions inventory

Highwood will conduct a comprehensive review of Enbridge's current methane emissions inventory, separating out the fugitive volumes from the other reported volumes (vented, flared, combustion). Highwood will review the calculation methodologies which are currently in use, and verify their accuracy, or provide recommendations for improvements to the calculations. A comparison between the results of the fugitive emissions surveys, and the reported fugitive volumes will be made, and any discrepancies will be flagged.

To complete this task, Highwood will require the following:

- Enbridge's complete inventory of all reported fugitive emissions within the GDS system(s), preferably including multiple years of reported emissions.
- Results of any fugitive emissions surveys that have been performed to date (this may include OGI and hi-flow sampler results, and any results obtained from top-down methods.)
- Calculation methodologies which are currently used to calculate fugitive emissions total volumes, and any assumptions that are made in the process.
- An estimate of the volume of UFGs.

Highwood will perform this analysis for the three segments as specified in the RFP (Distribution, Transmission, and Storage).

Task 1.2: Review of current leak detection practices

Using the data provided to Highwood in Task 1.1, and any other information concerning the deployment of previous and current leak detection campaigns, Highwood will perform an assessment of the efficacy of these programs. This will be a high-level, qualitative review, with the objective of identifying whether the current work practices could be improved upon and ensuring that all current and projected upcoming regulatory requirements are met.

- Review the technology that is in use by Enbridge's GDS for leak detection of each of the distribution, transmission, and storage business units.
- Review the coverage of the assets that are being achieved with each leak detection survey.
- Review the frequency of conducting surveys.

A potential outcome of this project task is a validation of Enbridge's current practices, or identification of areas of improvement, which would be addressed in further project phases.

Task 1.3: Overview of the potential methodologies for calculating fugitive emissions volumes

This project task will differ from task 1.1, which is a review of the methodology currently in use by GDS to calculate their fugitive emissions. The purpose of this task is to provide GDS with a comprehensive overview of all potential calculation methodologies which are appropriate for use in the different segments, while ensuring that any regulatory requirements are achieved.

Highwood will provide guidance on potential calculation methodologies which may be used which cover the following three scales of calculation:

1. Generic emissions factors
2. Company-specific emissions factors
3. System-wide measurements

In addition to the calculation methodologies, Highwood will provide an overview of the perceived workload required by GDS in order to use any of the potential methodologies. For example, for the use of company-specific emissions factors, Highwood will provide an overview of how to develop emissions factors, and a qualitative assessment of how much effort would be required by GDS to implement these measurements and emissions factors.

The assessment will also cover the advantages and disadvantages of each of the possible scales of measurement, as well as any limitations presented by an approach. For example, using generic emissions factors to estimate fugitive emissions is not considered an accurate approach, but may serve as a starting point in the absence of any estimates for these emitted volumes.

An overview of the uncertainties (in the measurements, sampling approaches, and calculation methodologies) will also be provided.

Scope 2: Technology and Measurement Methodology Evaluation

Objectives

The purpose of the second phase of the work will be an overview of all potentially appropriate and commercially available technologies which could be used by GDS for measurement of fugitive emissions.

Scope 2 encompasses 3 and 4 from the RFP objectives.

Approach and Work Plan

Task 2.1: Identification of potential technology options
Highwood has a technology database of over 200 commercially available technologies which can detect methane emissions. Highwood will draw from this database, and any products or technologies of existing interest to Enbridge, to prepare the following:

- A qualitative overview of the different sensing principles which exist within commercial methane sensing products, as well as an overview of the different deployment platforms (vehicles, aircraft, stationary, drones, etc.).
- Highwood will identify leading companies in each of the categories of highest interest to Enbridge, for specific use on each of the segments within the GDS. Note that a technology which is well suited to detection of fugitive methane from one segment may not be appropriate for use on another segment, due to many factors, such as technology limitations, performance, and urban settings.
- Through discussion with Enbridge, Highwood will create a short list of potentially suitable companies and technologies (with preference for proven/vetted technologies) and will prepare a technology evaluation matrix which ranks each of the methane measurement products of interest based on the following performance metrics:
    - equipment sensitivity (minimum detection limit)
    - quantification performance of the technology (ability to measure or calculate emission rates of detected fugitive emissions)
    - survey speed and coverage (including impacts on uncertainties)
    - estimated cost considerations
    - suitability for different asset types encountered in Distribution, Transmission, and Storage segments.
    - consideration of environmental limitations
    - comparison of associated uncertainties with consideration of, but not limited to:

    - minimum detection limit
    - different calculation methods
    - sample sizes
    - measurement frequencies

- Highwood will prepare recommendations for GDS to review and consider on the most suitable technology/technologies for each of the segment.

Task 2.2: Simulation Modeling of technologies of highest interest
Highwood, using the LDAR-Sim modeling software, will complete scoping-level simulation modeling of the technologies selected by GDS to be of the highest interest for each of the transmission, distribution, and storage segments.

The purpose of this exercise will be to determine which technologies are the best suited for deployment on Enbridge's systems, considering the specific circumstances of each. LDAR-Sim may validate the results of the qualitative analysis and provide a scientific justification for use of certain technologies in certain applications, to be submitted to the OEB. Highwood proposes that this LDAR-Sim analysis will be higher-level, with a more in-depth analysis considered as a potential follow-up project.

- Highwood will use Enbridge's fugitive emissions inventory to create a leak distribution profile for each of the segments.
- Using the LDAR-Sim software, Highwood will model the efficacy of the potential technologies selected in task 2.1.
- Highwood will prepare a brief report summarizing the results of each of the simulations, for each of the transmission, distribution, and storage segments, outlining which of the technologies of potential interest to GDS are likely to be the most suitable for reaching leak detection and mitigation goals, in line with OEB commitments.

Task 2.3: Cost of Deployment Evaluation
Highwood will prepare a high-level cost analysis of the investment requirements of deploying different technology, measurement, and frequency scenarios. Exact cost information is not publicly available for the majority of methane measurement companies and products; however, Highwood can provide an overview of the approximate cost bands for different deployment platforms, including:

- handheld, including OGI and hi-flow samplers
- aircraft (fixed wing planes and helicopters)
- unmanned aerial vehicles (drones)

- vehicles (mobile ground labs)
- satellites
- continuous / stationary monitoring systems

Cost requirements will vary with the deployment scenario, so Highwood will prepare an overview on how much sampling is required for each of the following scenarios, as well as an associated high-level cost/investment estimate:

- Regulatory Scenario (likely to be different for each of transmission, distribution, and storage)
- Whole system annual measurement
- Whole system, more than annual measurement
- Measurements required to develop company-specific emissions factors
- Sampling requirements to participate in voluntary initiatives (including OGMP 2.0 and GTI Veritas).

Scope 3: Recommendation and Implementation Plan

Objectives

The primary objective of this scope item is to provide a recommendation to Enbridge, based on the results of the analysis conducted in Scope 1 and 2 of this proposal, and to develop a roadmap for a phased implementation of fugitive emission measurement technologies, to meet OEB requirements.

Scope 3 encompasses 5 and 6 from the RFP objectives.

Approach and Work Plan

Task 3.1: Recommendations

Following the completion of the analyses conducted in Scope 1 and 2 of the proposal, Highwood will provide a recommendation of the best technology and methodology for deployment in each of the Distribution, Transmission, and Storage segments of Enbridge's operations.

- The recommendations will consider the technical suitability of methane detection products, the approximate cost effectiveness of deployment of these products, and any other operational practicability considerations.
- The recommendation will also consider whether technologies can be used to fulfil compliance obligations, such as leak survey and physical inspection/damage prevention purposes, as well as participating in any voluntary initiatives of potential interest to Enbridge.

Task 3.2: Implementation Plan

Highwood will prepare a roadmap for implementation of the recommended technology to measure fugitive methane, focusing first on the areas of Enbridge's operations which have been observed through previous measurement to have higher volumes of unaccounted-for gas.

- Highwood will ensure that all OEB requirements, and any requirements pertaining to the rebasing settlement with the OEB, are implemented at the beginning of the roadmap.
- Second priority will be given to higher emitting (observed and/or suspected) areas within the GDS.
- Resource requirements (including costs and workload for Enbridge staff) will be included, to ensure the implementation is phased such that demands are not overly onerous to Enbridge staff.
- Highwood will include any considerations around pilot testing of selected technologies (before a full-scale deployment occurs) within the implementation roadmap.

Scope 4: Preparation of the Deliverable

Highwood will prepare a report outlining the results of the analyses conducted through Scope 1, 2, and 3. The report will be fully-cited and will provide scientific basis for the analysis and recommendations. Highwood will present the results to key stakeholders at GDS for review and approval, with feedback incorporated into a final report that can be included as submissions to the Ontario Energy Board, and other applicable third parties.

Highwood will be available to be called as an expert witness on the contents of the report at any regulatory proceedings, as required, as well as any follow-up and/or support in response of interrogatories. These tasks are outside of the scope-of-work of the project, and will be charged as per Highwood's enclosed rate sheet or such other fees as agreed to between Highwood and Enbridge.

In addition to the specific deliverables outlined above, Highwood will:

- Conduct a kick-off meeting with the Highwood team and key stakeholders from GDS within two weeks of the contract award. A successful kick-off meeting will establish agreement among participants regarding the scope of work, timelines, and roles and responsibilities. Highwood will review the technical approach and lead the discussion on any clarifications or modifications required to the scope or workplan.
- Provide bi-weekly updates to GDS with progress update meetings and reports.

Timeline

- Project start date: September 15, 2023
- Emission Evaluation date: September 15, 2023 – October 29, 2023
- Technology and Methodology Evaluation: September 15, 2023 – Jan 5, 2024
- First draft report date: March 8, 2024
- Second draft report date: April 5, 2024
- Final report date: May 3, 2024
- Report complete date: June 30, 2024

Task	Sept	Oct	Nov	Dec	Jan	Feb	March	April	May	June
Scope 1: Evaluation of Enbridge's Fugitive Emissions inventory										
Scope 2: Technology and Measurement Evaluation										
Scope 3: Recommendations and Implementation Plan										
Scope 4: Report Writing and editing										
Expert Witness to the Ontario Energy Board										
Project Management										

Note that scope 4: report writing and editing will be performed as background tasks throughout the analysis phases of the scope, with formal completion of the task occurring in January through April 2024.

Cost Estimate

Highwood proposes "lump sum" value-based pricing for each of the work phases outlined in the Scope of Work. Note that GST is not included in these prices.

Item	Total Cost
Scope 1: Evaluation of Enbridge's Fugitive Emissions Inventory	$ 38,750
Scope 2: Technology and Methodology Evaluation	$ 44,750
Scope 3: Recommendations and Implementation Plan	$ 21,500
Scope 4: Preparation of the Deliverables	$ 42,500
Meetings and Project Management	$ 29,500
Total	**$ 177,000**

Expert witness testimony at regulatory proceedings and/or follow up support in response of interrogatories (IR's) are not included within this lump sum cost estimate and will instead be billed as time and materials based on Highwood's rate sheet below, or such other fees as agreed to between Highwood and Enbridge.

Pricing Table
Highwood Emissions Management Inc.

DATE: January 1, 2023

Role	Rate (CAD)
Principals	[redacted]
Senior	
Intermediate	
Associate	

Invoicing Schedule

Invoicing schedules will be laid out in the contract agreement and invoiced monthly based on percent completion of each milestone.

Experience and Qualifications

Effective decision-making in emissions management lies at the intersection of knowledge and data. Highwood offers integrated emissions management services underpinned by decades of combined upstream oil and gas emissions experience. Highwood identifies the most cost-effective ways to reduce emissions while considering the unique assets, goals, and financial constraints of each client. Highwood's high quality and cost-effective emissions management services have led to many impactful projects for our clients. Our industry leading GHG initiatives enable our them to actively manage their carbon portfolio to the highest standards while allowing dedicated focus on its core businesses.

Highwood highlights relevant experiences below to demonstrate its capacity to work across the spectrum of oil and gas emissions expertise, including cleaning and analysis of field measurement data, development of bottom-up emissions inventories, reconciliation with top-down measurements, and integrating diverse information sources into leading data analytical tools only available at Highwood. Our O&G engineers, data scientists, and academics embody both deep familiarity with established inventory methods and an ability to be creative and innovative, working at the cutting edge of emissions science. Our team has a demonstrated ability to work with diverse stakeholders and on multi-disciplinary teams with international reach, including:

- Public report on leak detection methods for natural gas gathering, transmission, and distribution pipelines. Highwood's expertise spans the full supply chain from upstream production through to end distribution. In our report on Leak Detection Methods For Natural Gas Pipelines, Highwood provides an overview of commercially available methods for detecting natural gas leaks from pipelines. We cover both legacy methods, such as visual surveys and handheld instruments, as well as a range of new, commercially available advanced solutions, such as drones, aircraft, and satellites.
- Expertise in LDAR-Sim. Highwood works with innovators and energy companies across the supply chain to design and implement world-class leak detection and repair (LDAR) programs. For many of our services, Highwood uses LDAR-Sim, an open-source virtual environment for evaluating the emissions reduction performance, cost-effectiveness, compliance, and safety of different LDAR programs. Leveraging our database of 180+ solutions, we combine the right technologies for your assets, budget, data needs, and emission reduction targets. We are leaders in demonstrating equivalency and achieving approval for new technologies in Alberta (Alt-FEMP), Colorado (A-AIMM), with the EPA (AMEL), and with ECCC (Alt-LDAR).
- Leading experience with OGMP 2.0, MiQ, Veritas, and other voluntary initiatives. Highwood is the Technical Director of Veritas, a GTI Energy Differentiated Gas Measurement and Verification Initiative, which is developing methodologies for measurement informed emissions intensity. In addition, Highwood used LDAR-Sim to evaluate methane detection technologies and inform the MiQ Standard. Highwood has published a novel report on 20+ voluntary emissions reduction initiatives available to the O&G industry, which can be downloaded **here** for free.
- Custom internal consulting tools available only to Highwood's clients. We have specialized tools for data management, quantification, and forecasting. Our proprietary 'Reduction Pathways' module

helps companies build and optimize roadmap scenarios to net zero (or any target). These tools greatly lower manual work and therefore cost. See Appendix A for more details.

- Expertise in bottom-up inventory data management and calculations across diverse production types, companies, and regions. Experience working with diverse oil and gas companies around the world to build inventories, perform quantifications, and lead regulatory and non-regulatory (e.g., ESG) reporting. We have conducted modeling across various basins, environmental conditions, production types, and emissions profiles. Our team has done Scope 1, 2, and 3 quantifications for large companies such as TC Energy and ChampionX.
- Participated in understanding, evaluation, and deployment of both bottom-up and top-down methane measurement systems. We have a proprietary database with over 200 methane measurement solutions and nearly 70 different abatement projects, including sophisticated cost models and interdependencies. We have worked with both industry and vendors to analyze field data, perform predictive analytics, and help operators understand emissions sources and opportunities to cost-effectively target the “low-hanging fruit” mitigation opportunities.
- Recognition as global leaders in emissions management. Our team has participated in numerous peer reviewed publications (e.g., here, here, and here) as well as teaching the world’s foremost methane measurement technology course. We have worked for years at the interface of regulators, industry, and innovators to streamline the approval of novel methane technologies as an alternative to regulatory-approved methods. Highwood’s President led ground-breaking work on technology approval that has been adopted by regulators across North America and endorsed by industry, innovators, academics, and regulators.

Expert Witness Experience

Highwood’s President, Dr. Thomas Fox, Ph.D, M.Sc, is a renowned expert in methane measurement technologies and methods and has previously acted as an expert witness in legal proceedings on related topics. Dr. Fox was an expert witness in a 2021 hearing before the Colorado Air Quality Control Commission, in the matter of opposition by the West Slope Colorado Oil and Gas Association (WSCOGA) to proposed revisions to the Colorado Air Quality Control Commission’s Regulations. Dr. Fox was present as an expert witness to explain and interpret the results of an LDAR-Sim (Leak Detection and Repair Simulator) report providing context to the impact of the proposed regulations.

Dr. Fox, completed a Ph.D. evaluating methane measurement technologies and methods. His expertise is in methane detection and quantification technology, low carbon differentiated commodities, and forecasting emissions management strategies through simulation. Thomas is a key contributor to both the GTI Energy Veritas Initiative and MiQ natural gas certification scheme. He also led invention and development of the Leak Detection and Repair Simulator (LDAR-Sim), an open-source software product used by industry and regulators to evaluate emerging leak detection technologies, data, methods, programs, and policies.

Our Experts

Thomas Fox (Ph.D., M.Sc., B.Sc.), President.
Thomas completed a Ph.D. evaluating methane measurement technologies and methods. His expertise is in methane detection and quantification technology, low carbon differentiated commodities, and forecasting emissions management strategies through simulation. At Highwood, Thomas works at the interface of industry, regulators, and innovators to evaluate and deploy cutting-edge emissions management solutions. Thomas is a key contributor to both the GTI Energy Veritas Initiative and MiQ natural gas certification scheme. He also led invention and development of the Leak Detection and Repair Simulator (LDAR-Sim), an open-source software product used by industry and regulators to evaluate emerging leak detection technologies, data, methods, programs, and policies.

Jessica Shumlich (P.Eng., MM), CEO.
Jessica Shumlich is the CEO and co-founder of Highwood Emissions Management with over 15 years of experience in energy companies, governments, tech developers, and startups. She has a background as a drilling engineer and supervisor for Shell and ended her tenure developing the GHG reporting plans and strategy for the global portfolio. She was the Program Manager for Energy Efficiency Alberta and Global Technical Director for Carbon Connect International, overseeing the design and delivery of the incentive programs that resulted in millions of GHG reductions. Jessica's expertise spans across Canada, the US, the Netherlands, the UK, and Germany.

Paul Ashford (B.A.Sc., P.Eng.), VP Consulting.
Paul has over 30 years of leadership and technical experience in upstream petroleum engineering, emissions, regulatory, and HSE. He has worked in various roles in Canada and internationally, adding value through optimization of production, costs, and assets, reducing emissions, and championing value-adding opportunities. At Highwood, he is leading up a team of world-leading experts helping clients to chart and implement their carbon reduction journeys, guiding them to achieve their GHG goals, achieve stakeholder recognition for their achievements, and preserve economic value.

Jeff Rutherford (Ph.D.), Director of R&D.
Jeff completed a Ph.D. at Stanford University and holds a B.Sc. in Mechanical Engineering. In 2021 and 2022, Jeff co-led the largest, to date, single-blind controlled release testing of airplane and satellite methane technologies. From 2017 to 2022, Jeff also contributed to the management and development of the open-source Oil Production and Greenhouse Gas Estimator, both in support of California's Low Carbon Fuel Standard and helping oil producers like Saudi Aramco and Chevron reduce emissions. Jeff has presented at international scientific conferences and his work has been published in many high-ranking journals.

Phil Tomlinson (PhD, P.Eng.), Senior Emissions Engineer.
Phil helps clients understand their pathways to emissions reduction providing recommendations on the best abatement projects customized to each unique asset base. With a decade of experience in the energy sector focused on pressure equipment integrity and leak prevention, Phil leverages his industry expertise to understands how emissions can be identified and mitigated. Utilizing analytical skills, Phil has extensive

experience in implementing data and process management systems across teams to develop and establish company best practices.

Brendan Moorhouse (B.Sc.), Fugitive Emissions Lead.
Brendan completed a B.Sc. Specialization in Geology from the University of Alberta which led to 5 years of oil and gas experience with a small exploration company. Brendan's combination of field and office experience fostered a deep familiarity with the oil and gas industry. Brendan is adept at extracting valuable insights from complex data and communicating insights through actionable visualizations. In addition, Brendan has become proficient in applying statistical modelling and machine learning to data to gain research or business insights.

Chelsea Goral (BAPC), Strategic Advisory Lead.
Chelsea has a decade of prior experience leading emissions quantification and reporting for an upstream oil and gas producer, Cenovus Energy. She has also supported many voluntary initiative activities including SASB, Greenhouse Gas Protocol requirements, MiQ, and OGMP 2.0. Under both regulatory and voluntary initiatives, she has undergone and supported clients in multiple GHG assurance activities. She also has training and experience in data management, analysis, and professional communications.

Heather Isidoro (P.Eng., MBA), Senior Consultant, Voluntary Initiatives.
Heather has 20+ years of oil and gas technical, business and leadership experience in natural gas. Prior roles were Business Development and reserves, focused on accretive and strategic growth. Heather is a Geological Engineer, with a Master's in Business Administration. At Highwood, Heather is the Senior Consultant on Voluntary Initiatives, helping energy companies who prioritize ESG meet their emissions goals above and beyond regulatory requirements.

Maddy Strange (B.Sc., EPt.), Reconciliation Technologist.
Maddy is an Environmental Professional In-Training, with a B.Sc. in Environmental Physics from the University of Calgary, and experience in the energy industry. Maddy has worked as ESG coordinator for a small producer and has done site reclamation/rehabilitation on abandoned and suspended oil and gas sites. At Highwood, Maddy's primary focus is on understanding detected emissions from various novel detection platforms and performing reconciliation with bottom-up inventories.

Bruna Palma (M.Sc., B.Sc.), Fugitive Emissions Analyst.
Bruna has five years of experience in R&D working on projects focused on renewable energy alternatives to fossil fuels. By working with research in academic and industrial settings, Bruna built a solid analytical background and ability to quickly evaluate and understand new technologies. She received her B.Sc. in Chemical Engineering (2017) from Rio de Janeiro State University in Brazil and her M.Sc. in Chemical Engineering from the University of Calgary (2022). At Highwood, Bruna is involved in projects focused on alternative detection technology evaluation for fugitive emissions management.

Antonio Monisit (M.Sc., B.Sc.), Differentiated Gas Technologist.
Antonio brings to the table almost a decade of experience in greenhouse gas emissions quantification. His extensive experience in emissions data processing allows him to anticipate, identify, and address potential

data gaps quickly. He has worked on advisory projects for clients on their voluntary emissions reduction initiatives, enabling them to evaluate the revenue potential of their certified gas. With his M.Sc. in Environmental Studies and his experience working as an environmental regulator, Antonio provides a different yet insightful set of perspectives to the team.

Katherine Elona (B.Sc.), Emissions EIT.
Katherine comes from an emissions consulting firm where she managed client data and performed GHG emissions quantifications. She holds a B.Sc. in Electrical Engineering and has extensive experience in using data analytics to process and analyze GHG emissions, specifically for preparing ESG reports and for complying with federal and provincial regulations such as AB TIER, NPRI, and GHGRP.

Nick Bosman (B.Sc.), Emissions EIT.
Nick helps clients quantify their GHG emissions and evaluates different emissions reduction strategies tailored to each client's unique asset base. Nick has over four years of previous work experience in environmental consulting and asset integrity in the upstream and midstream oil and gas sector. He holds a B.Sc. in Chemical Engineering from the University of Calgary. With his diverse set of skills and experiences, Nick produces detailed and comprehensive solutions for his clients.

ENBRIDGE

Request for Proposal

Project Name:	**OEB Fugitive Measurement Requirement Project**
Enbridge Gas Inc. Contacts	**Carbon Strategy (Peter Mussio, Ainslie Murdock, Ge Li)** **Engineering (Roya Jamarani)**
Proposal Due	**August 25, 2023**
Anticipated Contract Start Date	**September 15, 2023**

Project Purpose:

On June 28, 2023, Enbridge Gas (GDS) filed a partial settlement proposal to our regulator, the Ontario Energy Board (OEB), as part of a rebasing settlement on issues related to rate setting for 2024. As part of this settlement proposal, the following commitment was made to investigate fugitive emissions and consider impacts on unaccounted for gases (UFG).

> *In relation to fugitive emissions, which are a component of UFG, Enbridge Gas has agreed to investigate and determine an appropriate way to accurately measure fugitive emissions, including consideration of top-down measurements (i.e. by aircraft, satellite, and/or towers), with the goals of:*
>
> *(a) confirming the volume of fugitive emissions,*
> *(b) determining if recent UFG increases could be due to fugitive emissions, and*
> *(c) attempting to locate specific fugitive sources that can be mitigated.*
>
> *This would include all kinds of assets (transmission, rural & urban distribution, and storage).*
>
> *Enbridge Gas will file a robust investigation plan for consideration and determination in the 2024 deferral and variance account proceeding, which filing shall include justification of the planned approach including, without limitation, whether it will include aerial (i.e. top-down) investigation.*

This project will satisfy the Ontario Energy Board (OEB) requirement by delivering a report for consideration and determination in the 2024 deferral and variance account proceeding which will include a robust investigation plan for fugitive emissions.

The report will provide a comprehensive review of different fugitive emissions quantification methodologies and measurement technologies (including, but not limited to, hand-held instruments, vehicles, drones, aircraft, satellites). The report will also include recommendations specific to GDS's operations and an implementation plan to quantify fugitive emissions more accurately. This will support future efforts to assess fugitive emission sources and identify appropriate mitigation efforts.

ENBRIDGE

Project Scope:

GDS made a commitment as part of the rebasing settlement to investigate ways to accurately measure fugitive emissions, with the goals of confirming the volume of fugitive emissions, determining if recent UFG increases could be due to fugitive emissions, and attempting to locate specific fugitive sources that can be mitigated.

Fugitive emissions are understood to mean emissions from the unintended leakage of gas – this does not include venting, flaring, or combustion emissions.

The selected consultant will prepare a comprehensive study that includes:

1. Assessment of GDS's fugitive emissions inventory, broken down by segment (Distribution, Transmission, and Storage). This will include an overview of the current methods used to calculate fugitive emissions.
2. Review of GDS's current leak survey practices for Distribution, Storage, and Transmission.
3. Review of methodologies that can be used to calculate fugitive emissions (e.g., industry-average emission factors, company-specific emission factors, system-wide measurement). The methodology review should also include the following:
   - Advantages & limitations of different methods
   - Uncertainties associated with the assessed methods
4. Comprehensive review and comparison of different detection technologies that can be used to measure fugitive emissions:
   - Identification of commercially available technologies (including, but not limited to, hand-held instruments, vehicles, drones, aircraft, satellites)
   - Assessment of technology capabilities including but not limited to:
     - equipment sensitivity (minimum detection limit)
     - survey speed and coverage (incl. impacts on uncertainties)
     - suitability for different asset types encountered in Distribution, Transmission, and Storage (i.e., pipelines, services, stations, and customer meter sets)
     - consideration of environmental limitations - system response capabilities to extreme weather conditions
     - comparison of associated uncertainties with consideration of, but not limited to:
       - minimum detection limit
       - different calculation methods
       - sample sizes
       - measurement frequencies
   - Cost of deployment, including a high-level cost analysis of investments required by Enbridge under different technology, methodology and frequency scenarios, such as:
     - measurements of the whole system annually, or
     - measurements of a sub-section of assets to develop company-specific emission factors or

ENBRIDGE

- implement new reporting standards and protocols (e.g. OGMP, GTI Veritas).

Part of Enbridge's commitment to its regulator, the OEB, includes a requirement to justify the planned approach, including whether it will include top-down measurements (by aircraft, satellite, and/or towers). This study should evaluate and provide a scientific basis as to whether the deployment of top-down technologies such as satellite are feasible and cost effective for Enbridge's assets.

Understanding there are existing and emerging technologies, Enbridge is open to considering options that we may not have already identified but would prefer to investigate proven/vetted technologies.

5. Recommendations
    - The report should recognize the unique challenges within different segments and, if beneficial, provide separate technical evaluations and solutions for Distribution, Transmission, and Storage.
    - Consideration should be given to whether technologies can also be used to fulfil other compliance obligations, including leak survey and physical inspection for damage prevention.
    - Understanding the report will be submitted to the Ontario Energy Board, it should be well-cited, and recommendations should be justified, where possible, based on high quality sources.

6. Implementation Plan
    - Propose a roadmap for prioritizing and enhancing the measurement approach to meet OEB requirements, considering potential regulatory changes and other risk factors.
    - Implementation plan should include resourcing
    - Considerations of potential pilot testing, means and timing

The Report is intended to be shared with third parties, such as regulators, policy makers, industry partners, etc., for informational purposes to support their decision making. Enbridge notes that the final report will likely be filed with the 2024 deferral and variance accounting proceeding and will need to be defensible to the OEB. The selected consultant may be called upon as an expert witness at regulatory proceedings in defense of the findings/recommendations in front of OEB, as well as any required follow-up and/or support in response of interrogatories (IRs). A copy of the Acknowledgement of Expert Duty form has been attached for your reference, should you be called upon as an expert witness.

Consultant Qualifications:

- The selected consultant should have demonstrated experience of being an expert witness and be familiar with regulatory proceedings.
- The selected consultant should have demonstrated experience with methane measurement technologies
  - Preference for experience with both top-down and bottom-up methods
  - Preference for midstream and downstream experience (transmission and distribution)
- The selected consultant should be familiar with methane measurement protocols, including the OGMP 2.0 and Veritas Protocols.
- The selected consultant will be cognizant of existing studies (such as Highwood 2022 leak detection report) to avoid duplicating efforts. The selected consultant will check industrial data.

Project Requirements/Dependencies

- The project will use data from Enbridge's GHG inventory and Enbridge will support the work of the selected consultant as required.
- Consideration should be given to whether technologies can also be used to fulfil other compliance obligations, including leak survey and physical inspection for damage prevention.

Proposed Schedule – Deliverables & Resource Requirements

Deliverable:

Once the work is awarded, the consultant is expected to:

- Conduct a kick-off meeting with key stakeholders from Enbridge.
- Provide bi-weekly updates to Enbridge through progress update meetings/reports.
- Review the GHG emissions inventory working files, assess source contributions and missing sources, provide current methodology summary and current uncertainty analyses.
- Conduct technology and methodology review, including identification of commercially available technologies, detailed review of the technologies, cost and benefit analyses, and associated uncertainty analyses.
- Develop a draft report that includes all the required analyses outlined in the Scope of Work section.
- Present the results to key stakeholders at Enbridge for review and approval. Generate a final report with feedback and changes.

Timeline

Project start date: September 15, 2023

Emission Evaluation date: September 15, 2023 – October 29, 2023

Technology and Methodology Evaluation: September 15, 2023 – Jan 5, 2024

ENBRIDGE

First draft report date: March 8, 2024

Second draft report date: April 5, 2024

Final report date: May 3, 2024

Report complete date: June 30, 2024

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Recommendation 1: Develop company-specific emission factors based on source-level measurements for DO. [Exhibit D, Tab 1, Attachment 1, Page 95]

Question(s):

For Highwood:

a) Please explain what "company-specific emission factors" are and provide examples of how they are calculated and used by similar utilities.

b) Why not use internationally recognized emissions factors so that emissions can be compared and calculated in a standard manner consistent with recognized protocols?

c) Please provide any benchmarking against peer utilities that identify the current state and ultimate best practice targets for emission reductions.

Response:

The following responses were provided by Highwood Emissions Management:

a) As defined in the Highwood Report (please see EB-2024-0125 Exhibit D, Tab 1, Attachment 1, p. 19, Table 3), "company-specific emission factors are developed based on direct measurement of a representative sample of company assets. These factors reflect the emissions associated with the company's unique operational characteristics and components."

   Examples of how company-specific emission factors are calculated by other utilities can be found in the study cited in the Highwood Report "Development of company-specific emission factors with confidence intervals for natural gas customer meters in Southern California" (please see EB-2024-0125 Exhibit D, Tab 1, Attachment 1, p.117, reference vii).

b) As defined in the Highwood Report (please see EB-2024-0125, Exhibit D, Tab 1, Attachment 1, p. 19, Table 3), “generic emission factors are average emission rates for a given component, generally derived based on industry measurement campaigns”. Different countries and reporting bodies may recommend different emission factors for the same emission source categories (e.g. The U.S. Greenhouse Gas Reporting Program (GHGRP) supplies default EPA emission factors to be used in its reporting as applicable). Generic emission factors from different sources may differ in various aspects, including, but not limited to: research methodologies, regions covered, time frames assessed. Therefore, data quality can vary and be more or less relevant to a specific company’s emissions being reported. Increasingly, companies are developing company-specific emissions factors to better understand their emissions. The motive for this varies (i.e. voluntary initiatives call for company emissions factors) but ultimately, company-specific emissions factors provide a more accurate representation of a company’s emissions. Some of the information that is reflected in company-specific emission factors, which may not be accurately represented by generic emissions factors, includes:

I. Operating load conditions
   i. Sizing of the equipment and units.
   ii. Flow rates through the units.

c) Benchmarking against peer utilities is not recommended due to the variability that exists in equipment, operating practices, maintenance practices, leak survey and repair procedures, regulatory requirements and associated emissions profiles between different utilities. In addition, company-specific benchmarks and best practices are often kept confidential. Because of the ‘apples to oranges’ nature of this comparison due to variable operation environments, benchmarking against peers isn’t recommended. Therefore, the Highwood report focused on improving the emissions accounting and on developing accurate, company specific emissions factors which increasingly reference empirical measurements. Exploring the details of these measurements was a focal point of the Highwood report.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

The East Kingston Creekford Rd Reinforcement project was a planned capital reinforcement, and Enbridge Gas determined that this project could be deferred by implementing a supply side IRPA in the form of CNG beginning in 2022. [Exhibit H, Tab 1, Schedule 1, Page 18]

Question(s):

a) Please explain why the CNG was implemented in 2022 if the Enbridge AMP did not have construction of the Reinforcement planned until 2024.

b) Please confirm the date that the CNG facility was commissioned and the volumes (natural gas m3 and GJ equivalent) of CNG injected in that year.

c) Please confirm that the CNG facility is still operating in 2024 and the 2024 YTD volumes (natural gas m3 and GJ equivalent) of CNG injected into the system.

d) Please provide Enbridge's estimate for when the CNG facility will be required until and any documentation to support that estimate.

e) Does Enbridge own and/or operate the CNG facility or a third party. If it is a third party, please provide a copy of the agreement.

f) Is any portion of the CNG facility included in Enbridge Capital (i.e. rate base)? If yes, please provide the details.

g) Please confirm that no targeted DSM was leveraged for the area served by the pipeline and explain why not. If it was used, please provide the details and results.

Response:

a) Please refer to EB-2023-0092, Exhibit C, Tab 1, pages 22 to 24.

b) The in-service date of the CNG facility was January 23, 2023. A small volume of CNG was injected into the system as part of the testing process, and the balance of gas remaining in the CNG trailer was injected at the end of the winter period to empty out the trailer.

c) Not confirmed. The CNG facility is not operating in 2024 as the Contract turnback to reduce contract demand was sufficient as stated at Exhibit C, Tab 1, page 20, paragraph 12, and no injection occurred in 2024.

d) The CNG agreement was a two-year contract executed in 2022 and concluded in 2024.

e) Enbridge Gas does not own/operate the CNG facility. Enbridge Gas engaged a third-party vendor. Enbridge Gas has previously engaged with this third-party vendor and has a general service contract agreement in place. As such, the specific scope of work to the Kingston project is included in Attachment 1.

f) No.

g) Confirmed. As stated at Exhibit C, Tab 1, page 20, paragraph 12, a Contract turnback was implemented to reduce contract demand avoiding the facilities project. An enhanced targeted energy efficiency (ETEE) IRP alternative was not required.

ComTech Energy

SWIFT FUEL SOLUTIONS

Budgetary Proposal
CE-2163 R02
28 June 2022

Enbridge Gas / Peak Shaving / Kingston, ON

Quotation Number CE-2163 Rev. 02 – 28 June 2022

Attention: Steve Kay P.Eng.
Manager, Business Development
Enbridge Gas Distribution

We are pleased to provide you with our budgetary proposal for the rental of a natural gas decanting unit, two natural gas storage trailers and ComTech's Gas-As-A-Service to supply natural gas to allow Enbridge to meet peak demand. This proposal covers the technical specifications and pricing for the ComTech Energy CNG decanting unit, storage units and pricing for the supply of natural gas.

1.0 Technical Specifications and Requirements

We understand the technical specifications and requirements to be as follows:

1.1 Peak Shaving demand would be required at flow rates up to 3,000 cubic meters per hour for approximately 2-3 hours during morning & early evening periods during the coldest winter days. We are assuming roughly 10 days of service through a winter season
1.2 The equipment and gas supply would be required from December 1 to March 31. The start date of the service would be December 1, 2022.
1.3 The equipment would be rented on a monthly basis for a minimum of 4 months at a time.
1.4 The storage trailers will arrive full at the beginning of each 4 month period.
1.5 Natural gas cost would be provided at a "pass-thru" cost with the addition of a delivery charge
1.6 ComTech is responsible for providing a flat, compacted area that is free of debris. Space requirements and layout to be agreed upon 90 days before equipment delivery.

2.0 CNG Decanter Unit (x2)

2.1 Two 750,000 BTU Line Heaters with CSA B149.3 compliant fuel train/burners & Ontario CRN's
2.2 Each Heater is capable of 2000 m3/hr with an outlet temperature of 5°C during the worst case cold weather conditions.
2.3 Design Pressure: 3375 psig
2.4 First cut regulator: 2" CVS D-body with 4150 controls. Set at 500 psig
2.5 Second cut regulator: Fisher 627 Little Joe: Set at 250 psig (adjustable per Enbridge input)
2.6 PRV installed downstream of the second cut regulator will be sized for wide open flow from the regulator. Set pressure to be determined to protect Enbridge's downstream piping system.
2.7 Inlet connections: 1" Oasis 300 Series
2.8 Exposed System Piping: A333 Gr.6
2.9 Design Codes: CSA B51, CSA B108, CSA 22.1
2.10 Approvals. TSSA approvals to be obtained during site installation
2.11 ESD's on low inlet or discharge temps

2.12 Connected to our ComTech/4Refuel Web Interface to view performance and gas usage remotely

3.0 Unloading Post

ComTech Energy proposes two custom-built unloading posts to provide the required connection between the tube trailers and the decanting unit. It will be built with the following specifications:

3.1 Design Pressure: 4500 psig
3.2 2" stainless steel pipe manifold
3.3 Two 1" virtual pipelines hoses with Oasis HC308 couplings per post
3.4 American Iron Works Whip Sock installed on both ends of hose
3.5 Stainless Steel B16.34 shut-off valve with spring loaded venting valve.
3.6 Design Codes: CSA B51, CSA B108
3.7 Ontario CRN's on all pressure-wetted components

4.0 Tube Trailers

ComTech Energy proposes utilizing our two existing type 1 steel tube trailers with the following specifications

4.1 14-Tube Type 1 Steel Tube Trailer, 8188m3 storage at 2748 psig. 4 axle trailer with front steer axle, Air Ride Suspension
4.2 16-Tube Type 1 Steel Tube Trailer, 8871 m3 storage at 2538 psig, 5 axle trailer with front and rear steer axles, Air Ride Suspension
4.3 All trailers inspected with up to date certifications.
4.4 Total Gas Connected at beginning of each day is 17,059m3. We anticipate refilling one trailer mid-day during high demand periods

5.0 Site Connection

ComTech Energy will provide a 3" CL300 RF Flange for connection from the decanting skids. Piping connections from this flange to the injection point will be by ComTech.

ComTech Energy

SWIFT FUEL SOLUTIONS

Budgetary Proposal
CE-2163 R02
28 June 2022

6.0 Pricing (based upon a 2-year contract)

Line Item	Equipment Rental Charges	# of Months	Monthly Price (CAD)	Total Price (CAD)
1	**Equipment Rental Fee** Includes shipping to site, equipment setup and any required equipment maintenance	[redacted]	[redacted]	$270,800.00
			Total Equipment Rental Charges per Year	**$270,800.00**
Line Item	**Gas Delivery Charge**	**Qty**	**Unit Price (CAD)**	**Total Price (CAD)**
2	**Delivery of Gas to Site** (charge to transport 1 Storage Trailer to and from the Fill Station each time it is filled)	[redacted]	[redacted]	$1,440.00

NOTE:

1. Natural gas cost is provided at a "pass-thru" cost and is not included in the prices above.
2. Natural gas cost and gas delivery charge will be invoiced on a monthly basis in addition to the monthly equipment rental fee.
3. Pricing is shown for the first year. Subsequent years pricing will be increased by 3% annually.

7.0 General Notes.

7.1 **Confidentiality.** The customer acknowledges and agrees that certain sensitive information (of a financial nature, commercial, or other relevant matters) are contained in this bid and will be disclosed during negotiations. All such information will be treated by the customer and its employees and agents in a strictly confidential basis and may not be disclosed to any third party without the prior written consent of ComTech Energy Inc., except as may otherwise be required by law.

7.2 **Currency.** All prices are in Canadian dollars

7.3 **Payment Terms.**
- Payment terms are (upon approved credit)
- Gas and Gas Delivery Charges are due Net 30 days monthly based on actual usage
- Equipment will not be shipped until credit is approved.
- These prices are subject to the validity and terms stated in the accompanying quotation, and do NOT include any Provincial/State and/or Federal taxes, customs, duties, or documentation charges.

7.4 **Escalation.** Prices shown are for 2022 and will be escalated 3% per annum.

7.5 **Lead Time.** The equipment will be at site on or before December 1 and will remain at site until March 31of each calendar year.
PO must be received by July 15th, 2022 in order to meet operational requirements for December 1, 2022.

7.6 **Proposal Validity.** This proposal is valid for 60 days.

ComTech Energy

SWIFT FUEL SOLUTIONS

Budgetary Proposal
CE-2163 R02
28 June 2022

We appreciate the opportunity to provide this proposal and look forward to working with you on this project. Please do not hesitate to contact us with any questions that you might have.

Sincerely,

Marie-Genevieve Poitras
Vice President, Customer Experience
ComTech Energy
mg.poitras@comtechenergy.ca
(514) 222-6200

Guy Couturier
Senior Specialist, Sales Operations
ComTech Energy
guy.couturier@comtechenergy.ca
(514) 777-9544

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

October 31, 2023 – Enbridge Gas filed the Asset Management Plan Addendum – 2024 under EB-2020-0091 which included an updated version of the previously filed Appendix B on March 8, 2023 at EB-2022-0200. This updated Appendix B filed on October 31, 2023 included the original 3,087 investments as well as 1,194 new investments to Appendix B. [Exhibit H, Tab 1, Schedule 1, Page 7]

Question(s):

a) Please confirm that the East Kingston Creekford Rd Reinforcement is the only IRP related alternative implemented by Enbridge. If not correct, please provide details on IRPAs implemented and their success.

b) In addition to this Kingston project, please provide a list of IRP alternatives proposed to be implemented based on the 4,281 (3,087 + 1,194) projects in the AMP and a schedule of when they are proposed to be implemented.

Response:

a) Confirmed.

b) As the IRP evaluation process is still in progress, Enbridge Gas does not have a list of IRP alternatives proposed to be implemented based on the projects in the AMP or a schedule of when they will be implemented.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

EB-2024-0125, Exhibit H, Tab 1, Schedule 1, Page 36.

Question(s):

a) Please describe what is meant for each project in the table where it notes "Rejected - No longer in 10 year AMP".

b) Please describe how a project assessment results in a determination of "Low Cost, Low Value Category" and provide any supporting materials that help define when a project should be put in that category (i.e. it is not defined in the IRP Assessment Screening and Evaluation Guidelines).

c) Please provide the documentation that supports the Status for each project in the table.

Response:

a) Investments categorized as "Rejected - no longer in the 10 year AMP" in the "Status" column no longer have a project need required within the 10-year Asset Management Plan.

b) Please see Exhibit H, Tab 1, Schedule 1, pages 6 -11, 2023 IRP Evaluation Updates.

c) There is no standardized documentation that supports the status on a project level basis. Enbridge Gas conducted system modelling to determine whether the project need for each of these investments was still required within the 10-year Asset Management Plan following the System Reinforcement Plan update and introduction of Energy Transition adjustments to demand forecasts. Upon identification of investments where the project need is no longer required, there is a series of steps executed in Copperleaf to remove this investment from the Asset Management Plan.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

IRP Assessment Screening and Evaluation Guidelines (EB-2024-0125, Exhibit H, Tab 1, Schedule 1, Page 87)

Question(s):

a) Enbridge had filed a preliminary draft version of IRP Screening Guideline in EB-2022-0200. Is this the first time Enbridge has filed the the IRP Assessment Screening and Evaluation Guidelines?

b) What approvals (if any) is Enbridge requesting related to the IRP Assessment Screening and Evaluation Guidelines?

Response:

a) Yes. Since the filing of the draft Binary & Technical screening document[1] in, Enbridge Gas has consulted with the IRP Technical Working Group (TWG) and updated the document to provide additional clarity on the screening requirements based on feedback from the TWG. This document is now called the IRP Assessment Screening and Evaluation Guidelines.

b) Enbridge Gas is not seeking approval related to the IRP Assessment Screening and Evaluation Guidelines. Enbridge Gas has and continues to engage with the IRP TWG for feedback on the IRP evaluation process.

[1] EB-2022-0200, Exhibit JT5.36, Attachment 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

B-2-2

Question(s):

Please provide a breakdown and explanation of the main drivers of Enbridge earnings being below the 2023 deemed ROE.

Response:

In relation to the "deemed" or OEB Allowed ROE of 9.36% for 2023, Enbridge Gas achieved an actual ROE of 6.352%, a 3.008% deficiency. The main drivers of this deficiency are noted in Table 1.

Table 1
Main Drivers of 2023 Deficiency compared to OEB Allowed ROE

Line No.	Particulars	Amount ($ millions)
1	Write-off of net integration capital costs	84.3
2	Impact of unfavourable weather	70.9
3	Write-off of GTA and WAMS related costs	41.0
4	Subtotal	196.2

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

C-1, p.2

Question(s):

With respect to the Accounting Policy Changes Deferral Account, Enbridge states that it "is seeking final disposition of the remaining balance in the APCDA, reflecting the variance between the forecast balance approved in the EB-2022-0200 Phase 1 Decision and Order, and associated Interim Rate Order dated April 11, 2024, and the final actual balances calculated through December 31, 2023." Please detail where in the EB-2022-2000 record did Enbridge propose, and the OEB agree, that forecast balances disposed in the EB-2022-0200 Phase 1 would be subsequently true-up.

Response:

In the Company's pre-filed evidence in the 2024 Phase 1 Rebasing application, Enbridge Gas proposed the following:

> As the final balances are not known at this time for all the accounts, Enbridge Gas is proposing disposition on an interim basis[1]. Enbridge Gas will seek final disposition of the D&VA balances, calculated as the difference between actual balances as of December 31, 2023, and balances approved for disposition as part of this Application, within the Company's 2023 annual earnings sharing and D&VA disposition proceeding.[2]

Subsequently, in the OEB Decision for the 2024 Phase 1 Rebasing Settlement Proposal, it was noted:

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

[1] Enbridge Gas is seeking final disposition of the Impacts Arising from the COVID-19 Emergency Deferral Account, Transitional Impact of Accounting Changes Deferral Account, and Transitional Pension Balance. The remaining accounts proposed for disposition as part of this Application are on an interim basis.
[2] EB-2022-0200, Exhibit 9, Tab 2, Schedule 1, p.1, para.3.

> 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 which relate to accelerated CCA costs for integration projects (forecast at approximately $5 million).
> - Parties do not agree to the clearance of the balance in the Accounting Policy Changes Deferral Account (APCDA).[3]

As such, the OEB reported its findings on the 2024 Phase 1 Rebasing Settlement Proposal:

> The OEB accepts the updated partial settlement proposal, as filed on July 14, 2023. The OEB finds that implementation of the settlement proposal affecting rates effective January 1, 2024 will result in reasonable outcomes for both Enbridge Gas and its customers. [4]

Accordingly, and as noted in the response at Exhibit I.PP-4, Enbridge Gas is of the understanding that the accounting policies and treatment of disposal of balances as proposed were settled upon by all parties and approved by the OEB within this Decision on Settlement Proposal.

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[3] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.58.
[4] EB-2022-0200, Settlement Agreement, August 17, 2023, p.5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

C-1, p.23

Question(s):

With respect to the Getting Ontario Connected Act ("GOCA") Variance Account:

a. For each year since 2017, please provide Enbridge's actual locate costs.
b. For each year since 2017, please provide Enbridge's actual locate volume.
c. For each year since 2017, please provide Enbridge's actual VMS costs.
d. For each year since 2017, please provide Enbridge's actual VMS volume.
e. Please confirm that it is Enbridge's position that the entire increase in locate and VMS costs since 2021 is as a result of Bill 93. If not confirmed, please show where those costs not caused by Bill 93 are excluded from the GOCA VA.
f. [EB-2023-0143 Decision and Order, Schedule B] Referencing the Gas Utility GOCA VA Accounting Order, please explain how VMS costs are eligible for inclusion.

Response:

a) Enbridge Gas actual annual locate costs:
   i. 2017 = $31.7 million
   ii. 2018 = $33.7 million
   iii. 2019 = $38.4 million
   iv. 2020 = $33.5 million
   v. 2021 = $34.5 million
   vi. 2022 = $39.9 million
   vii. 2023 = $65.8 million

b) Enbridge Gas actual annual locate volumes:

   i. 2017 = 1.09 million
   ii. 2018 = 1.16 million
   iii. 2019 = 1.10 million
   iv. 2020 = 1.01 million
   v. 2021 = 1.07 million
   vi. 2022 = 1.02 million
   vii. 2023 = 976K

c) Data regarding costing for vital main standby is only available from 2021 to 2023 due to integration between systems and VMS process alignment between legacy Enbridge Gas companies.

   i. 2021 = $3.30 million
   ii. 2022 = $3.11 million
   iii. 2023 = $8.32 million

d) Data regarding hours for vital main standby is only available from 2021 to 2023 due to integration between systems and VMS process alignment between legacy Enbridge Gas companies.

   i. 2021 = 40,086
   ii. 2022 = 36,532
   iii. 2023 = 57,046

e) Confirmed. It is Enbridge Gas's position that the increase in locate and VMS costs from 2021, above the OEB approved Price Cap Index, is the result of Bill 93's impact on the locating industry in Ontario.

f) It is the view of Enbridge Gas that vital main standby (VMS) is eligible for inclusion because VMS is part of the location process for high risk / high consequence pipelines, and the activity is performed by the same LSP contractors that are involved in all locates. Please refer to the response at Exhibit I.OGVG-2 for background on the impact of Bill 93 on the locating industry and refer to the response at Exhibit I.EP-8 for further background on VMS and its inclusion in the GOCA variance account.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

D-1, p.58

Question(s):

Please provide a copy of all internal business cases (or similar documents) regarding Enbridge's Fugitive Emissions Measurement Plan and the proposed pilot project.

Response:

As discussed in pre-filed evidence,[1] in the Partial Settlement Proposal for the Company's 2024 Phase 1 Rebasing proceeding Enbridge Gas committed to:

> …investigate and determine an appropriate way to accurately measure fugitive emissions, including consideration of top-down measurements (i.e., by aircraft, satellite, and/or towers), with the goals of: (a) confirming the volume of fugitive emissions, (b) determining if recent UFG increases could be due to fugitive emissions, and (c) attempting to locate specific fugitive sources that can be mitigated. This would include all kinds of assets (transmission, rural & urban distribution, and storage). Enbridge Gas will file a robust investigation plan for consideration and determination in the 2023 deferral and variance account proceeding, which filing shall include justification of the planned approach including, without limitation, whether it will include aerial (i.e., top-down) investigation.[2]

To satisfy these commitments, Enbridge Gas determined that it was necessary to expand the Company's actual measurement of fugitive emissions to more accurately quantify volumes and initiated the FEMP Project in August 2023. No business cases were required or developed.

Please see the response at Exhibit I.PP-11, for a copy of the RFP and Highwood contract related to Enbridge Gas's FEMP Project.

[1] Exhibit D, Tab 1, pp.58-59.
[2] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, p.37.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

D-1, p.61

Question(s):

Enbridge states that its "2022 leak volumes were 18,118 103m3, (including leak volumes related to both DO and STO), representing 4% of the Company's 2022 UAF/UFG volumes (EGD and Union Rate Zones combined)."

a. Please provide the cost of what the 2022 leak volumes represent.

b. Please provide the 2023 leak volumes and the cost it represents.

Response:

a) Please see the response at Exhibit I.CCC-4 part g).

b) Accurately calculating the specific costs of leaks or any other contributing sources of UFG is extremely complex and time consuming. Therefore, in Table 1, Enbridge Gas has produced a simplified illustrative example estimating the historical UFG costs related to leaks by applying a calculated ratio (2023 leak volumes vs 2023 total UFG volumes) to total 2023 UFG costs[1] .

Table 1
Enbridge Gas 2023 Estimated Leak Volumes and Costs

Year	2023 Leak Volumes (10^3m^3)	Estimated Leak Costs ($ Million)
2023	21,328	4.3

[1] Please see the response at Exhibit I.ED-4 parts a) & b), for historical UFG volume and cost details.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

D-1, p.64]

Question(s):

Table 12 shows forecast 2025 spending that would be recorded in the proposed Fugitive Emissions Measurement Plan DA (FEMADA) for administration and pilot costs:

a. Are any of the cost elements capital costs, and if so, is the 2025 forecast costs a revenue requirement number?

b. If the answer to part (a) is yes, please provide a revised version of the table showing capital costs separately, and a breakdown of the revenue requirement calculation.

c. Are the administration costs directly related to undertaking the pilot? If not, please detail which costs would be incurred if there was no pilot project.

d. Please confirm that Enbridge is seeking approval of the FEMADA, and that the account is not restricted to spending related to the pilot project.

Response:

a) and b)

As stated in the Company's pre-filed evidence,[1] the FEMADA will include incremental operating costs as well as costs associated with any required capital investment, including return on rate base, depreciation expense, and associated income taxes.

At this time, Enbridge Gas does not anticipate that it will incur any capital costs as it expects to employ an equipment leasing model, depending on vendor offerings and quoted costs. Enbridge Gas may consider incurring capital costs in the future,

[1] Exhibit D, Tab 1, Attachment 2, p.1.

whereby the revenue requirement associated with those capital costs will be included in the deferral account.

c) The proposed FEMADA administration costs are primarily related to undertaking the pilot. These costs would be appreciably reduced if there was no pilot project (including both the company-specific emission factor pilot and the mobile-ground technology pilot). Potential costs that may still be incurred, could include:

- Consulting support, as Enbridge Gas may continue to work to develop robust and credible measurement procedures, to be proactive in a changing regulatory/methane landscape.

- Other miscellaneous costs, including training, conferences and memberships associated with methane measurement technologies and methodologies, to stay abreast of new technologies and methodologies.

d) Confirmed.

As stated in the Company's pre-filed evidence,[2] Enbridge Gas is seeking approval of the FEMADA at this time to record as a debit/(credit) in the account incremental administration costs related to the proposed Fugitive Emissions Investigation Plan,[3] including the proposed technology pilot. The nature of future costs to be recorded is described in greater detail in the Company's evidence[4] and the proposed associated accounting order[5], and includes:

- implementation of measurement technologies and development of company-specific emission factors,

- configuration of IT systems,

- incremental staffing,

- consulting support for the development of company-specific emission factors and measurement pilot program and related analysis, and

- other miscellaneous costs (including training, conferences, and memberships associated with methane measurement technologies and methodologies).

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[2] Exhibit D, Tab 1, Attachment 2, p.1.
[3] Exhibit D, Tab 1, pp.62-64.
[4] Exhibit D, Tab 1, pp.64-66.
[5] Exhibit D, Tab 1, Attachment 2, p.1.