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October 29, 2026

VIA RESS AND EMAIL

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

Dear Ritchie Murray

Re: Enbridge Gas Inc. (Enbridge Gas or the Company)
Ontario Energy Board (OEB) File No.: EB-2026-0108
2025 Utility Earnings and Disposition of Deferral & Variance Account Balances Application – Interrogatory Responses

In accordance with the OEB's Procedural Order No. 1 dated September 17, 2026, enclosed please find the interrogatory responses of Enbridge Gas.

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

Exhibit	Brief Description	Basis for Confidentiality
I.FRPO-18, Attachment 1	Monthly commodity price data and unit price of storage services.	Enbridge Gas considers the information market sensitive pricing information. This information fits in with items a) (i) - (iii) and b) in the OEB's Considerations in Determining Requests for Confidentiality. [1] This is also information that the OEB has indicated will be presumptively considered to be confidential – unit pricing of a third party. [2]

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

I.FRPO-26, Attachment 1	Methodology – Description of the techniques and assumptions used to assess geohazards Results – Site specific Probability of Failure (PoF) results	This information constitutes proprietary scientific and technical material developed and utilized by the Consultant while providing geohazard assessment services. The methodologies reflect specialized knowledge, analytical approaches, and professional expertise that are not publicly disclosed and are treated confidentially by the Consultant. The site-specific PoF results are direct outputs of these proprietary methodologies and therefore reveal information regarding the underlying analytical processes and evaluation criteria. Public disclosure of either the methodologies or the resulting PoF's could prejudice the Consultant's competitive position by enabling competitors to gain insight into the Consultant's technical approaches and work product without incurring the associated development costs. As such, disclosure could reasonably be expected to result in commercial harm to the Consultant. This information fits in with items a) i. and iv. and b) in the OEB's Considerations in Determining Requests for Confidentiality [3]

Generative artificial intelligence was used to generate content within this filing. Enbridge Gas confirms that such content has been verified for accuracy by the Company without the assistance of generative artificial intelligence.

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-2026-0108 - Intervenors

[3] Appendix A to the OEB's Practice Direction of Confidential Filings.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, UFG Volume Variance Account
EB-2025-0155, 2024 DVA/ ESM, Decision and Order, June 25, 2026, pp. 9

Actual UFG volumes for 2025 were 370,109 10^3m^3. The variance between actual and forecasted UFG volumes of 126,428 10^3m^3 resulted in a debit balance of $10.6 million in the UFGVVA, plus interest (50/50 sharing). Historical UFG volumes have shown volatility (e.g., 334,888 10^3m^3 in 2024 and 370,109 10^3m^3 in 2025, both well above the OEB-approved forecast of 243,681.5 10^3m^3).
In Enbridge Gas's 2024 DVA Decision and Order the OEB directed Enbridge Gas to provide a detailed report on the measures it has taken to address the issue of UFGVVA associated with estimated billing.

Question(s):

a) Please provide a breakdown of the 2025 actual UFG into non-emissions-related, emissions-related, and unexplained components (in 10^3m^3 and dollars).
b) Does Enbridge Gas expect actual 2026 UFG volumes to return closer to the approved forecast level? If not, please explain why not and discuss any ongoing impacts from methodology harmonization or other factors.
c) Other than any residual methodology effects, please discuss any other potential factors that contributed to the 2025 UFG variance (including weather, system operations, or measurement issues).
d) Please provide the report requested by the OEB on the measures it has taken to address the issues of UFG and estimated billing.

Response:

a) and c)

Table 1 presents best estimates as of the time of filing of the volumetric impacts of known contributing sources of 2025 and updated 2024 Unaccounted for Gas (UFG) that have been investigated. Table 1 includes regulated and unregulated UFG

estimates. Enbridge Gas has identified nearly 57% of contributing sources of UFG impacting 2025 and 49% for 2024.

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

True-ups and accounting adjustments related to the estimation used in both the billing and accounting processes will continue to impact the UFG volumes estimated in Table 1. As the true-ups and adjustments are completed, Enbridge Gas expects the remaining Unexplained UFG Volumes associated with 2025 will be reduced[1].

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

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

Dollars provided in Table 1 are for illustrative purposes only and do not reflect actual costs by contributing source. The average of the Weighted Average Reference Price (WARP) for 2025 ($171.984/$10^3m^3$) and 2024 ($140.783/10^3m^3) were applied to the volumetric impacts by contributing source to determine dollars in Table 1. Actual UFG costs are determined by taking the total actual annual UFG volume variance, which is then re-profiled in proportion to actual consumption volumes and costed at monthly approved weighted average reference price (QRAM) as per the accounting order.

Enbridge Gas will continue to investigate the Unexplained UFG volumes.

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

Table 1
2025 and 2024 Updated UFG Contributing Sources (10^3m^3)

Line No.	Particulars	Notes	10^3m^3 (a) 2025	10^3m^3 (b) 2024	Million $ (c) 2025	Million $ (d) 2024
	Non-Emissions Related Investigation Estimates					
1	Gas Accounting Adjustments		6,867	(3,113)	1.2	(0.4)
2	Other Prior Period Billing Adjustments	(1)	7,637	11,045	1.3	1.6
3	Unbilled Estimates	(2)	-	46,438	-	6.5
4	No-Bills Estimates	(3)	(383)	(25,389)	(0.1)	(3.6)
5	Storage Inventory Audits and Adjustments		9,719	8,763	1.7	1.2
6	Minimum Linepack		(43)	980	(0.0)	0.1
7	Gate Station Measurement Variation		83,163	80,441	14.3	11.3
8	Residential Meter Variation		56,271	48,235	9.7	6.8
9	Total Non-Emissions Related Investigation Estimates	(4)	163,231	167,400	28.1	23.6
	Emissions Related Estimates					
10	Fugitive Emissions Inventory Estimated Volumes	(5)	23,000	23,039	4.0	3.2
11	Total Emissions Related Estimates		23,000	23,039	4.0	3.2
12	Enbridge Gas Total Annual UFG Volumes	(6)	435,240	372,399	74.9	52.4
13	Unexplained UFG Volumes for Investigation	(7)	249,009	181,960	42.8	25.6

Notes:

(1) Prior period billing adjustments relating to an applied year/month in a previous fiscal year unrelated to No-Bills and Unbilled estimates.
(2) 2024 Impact from Harmonization of LUG Unbilled methodology only.
(3) Residual 2024 Impact from Harmonization of LUG No-bills methodology only.
(4) Calculated as the sum of lines 1-8.
(5) Fugitive volumes, as related to the fugitive emissions reported to the provincial and federal GHG reporting programs, that result from the unintended releases of gases from equipment leaks and third-party damage events.
(6) Total unregulated and regulated UFG volume.
(7) Calculated as the difference between line 12 and the sum of lines 11 + 9.

b) Enbridge Gas is not able to predict 2026 UFG levels. The contributing factors discussed in part a) all contribute to UFG in different ways based on the point in time nature of UFG reporting.

d) In its EB-2025-0155 Decision and Order, the OEB directed Enbridge Gas to provide a detailed report outlining the measures undertaken to address estimated customer bills and meter reading performance.

The OEB stated:

> The OEB does not accept Energy Probe's proposal to defer a portion of the UFGVVA balance associated with estimated billing. The evidence supports Enbridge Gas's position that estimated bills do not create persistent UFG

> balances over time. Having said that, Energy Probe has raised questions that relate to the OEB's ongoing concern about estimated customer bills. The OEB directs Enbridge Gas to provide a detailed report on the measures it has taken to address this issue as part of its next DVA application considering its annual performance scorecard.[3]

Enbridge Gas filed the requested report as Exhibit G, Tab 1, Schedule 3 of this proceeding. Exhibit G, Tab 1, Schedule 3 describes the role of estimated billing within the customer billing process, meter performance trends and challenges, customer complaint trends and the actions Enbridge Gas has taken and continues to take to improve meter reading performance and the customer experience associated with estimated billing.

As discussed in that report, estimated billing is a standard and necessary component of utility operations and an established part of Enbridge Gas's meter reading and billing process. Estimated billing serves as an interim billing mechanism and does not determine the customer's final consumption. Once an actual meter reading is obtained, the customer's account is reconciled to reflect the actual consumption. The data demonstrates that estimated bills do not create persistent UFG over time because accounts are reconciled once an actual meter reading is obtained.

[3] EB-2025-0155, Decision and Order, June 25, 2026, p.9.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 6, Parkway Delivery Obligation Variance Account
The $2.558 million debit balance represents the difference between the OEB-approved Parkway Delivery Commitment Incentive (PDCI) cost of $14.150 million recovered in rates and the actual PDCI cost of $16.708 million. Higher costs are primarily attributed to higher actual PDCI volumes than the forecast of 79 PJ. Enbridge Gas was not able to shift any Parkway Delivery Obligation (PDO) volumes in 2025 due to a pressure restriction on the NPS 26 Trafalgar pipeline.

Question(s):

a) Please provide the underlying calculations for the actual PDCI cost of $16.708 million.
b) Please explain the factors that caused PDCI volumes to exceed the forecast of 79 PJ.
c) Please provide further detail on the pressure restriction (timing, magnitude, expected duration) and why no market-based alternatives were practical in 2025.
d) Please provide an update on the pressure restrictions and if/ when they will be lifted.
e) Please provide the forecast PDO volumes for November 1, 2026 and November 1, 2027 (with and without EGD rate zone customers) and confirm whether any capacity is expected to become available in the next two years that could reduce the PDO.
f) What would happen to PDO volumes once the NPS 26 Trafalgar pipeline restriction is lifted?

Response:

a) Please see Table 1.

Table 1
2025 Actual Parkway Delivery Commitment Incentive (PDCI) Costs

Line No.	Particulars	Jan - Jun	Jul - Sep	Oct - Dec	Total
		(a)	(b)	(c)	(d) = (a) + (b) + (c)
1	Parkway Delivery Volumes (TJs)	45,294	23,192	23,108	91,594
2	PDCI Rates (1)	0.169	0.168	0.177	0.171
3	Actual PDCI Cost ($millions) (line 1 x line 2)	7.655	3.896	4.090	15.641
4	Market Based Solution - Firm Shift Exchange ($millions) (2)	0.534	0.267	0.267	1.067
5	Total Actual PDCI Cost ($millions) (line 3 + line 4)	8.188	4.163	4.357	16.708

Notes:
(1) Jan to Jun: January 2025 QRAM EB-2024-0326, Exhibit F, Tab 1, Schedule 1, Appendix C, p. 8, Line 166 and April 2025 QRAM EB-2025-0078, Exhibit F, Tab 1, Schedule 1, Appendix C, p. 8, Line 166
Jul to Sep: July 2025 QRAM EB-2025-0165, Exhibit F, Tab 1, Schedule 1, Appendix C, p. 8, Line 166
Oct to Dec: October 2025 QRAM EB-2025-0244, Exhibit F, Tab 1, Schedule 1, Appendix C, p. 8, Line 166
(2) EB-2022-0133, Exhibit B, Tab 1, Schedule 1, p.11, Section 1.6

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

c-d) The restriction is due to an integrity feature identified along sections of the NPS 26 Dawn Parkway pipeline. Enbridge Gas will be filing a leave to construct application to address the restoration of the NPS 26 pipeline capacity and details related to mitigation and/or rehabilitation options will be discussed in that proceeding.

e) Please see Table 2 for the Nov 1, 2026 and Nov 1, 2027 Parkway Delivery Obligation (PDO) forecasts. No capacity is expected to become available in the next 2 years to reduce the PDO.

Table 2
PDO Forecast

Line No.	Particulars: Zones	Forecast (TJ/D) 1-Nov-26	Forecast (TJ/D) 1-Nov-27
1	UG Rate Zone	255	265
2	EGD Rate Zone	13	13
3	EGI Total	268	278

f) The impact on PDO of the NPS 26 restriction being lifted will depend on the timing of the removal of the restriction, and the demands on the Dawn Parkway system at that time.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 8, Facility Carbon Charge Variance Account
Enbridge Gas recorded a credit balance of $0.74 million. The $7.68 million related to Emissions Performance Standards (EPS) volumes is based on satisfying the full 2025 EPS compliance obligation by paying the excess emissions charge of $95/t$CO_2$e. The deadline to meet the 2025 obligation is December 1, 2026. Enbridge Gas retains the option to purchase EPUs.

Question(s):

a) Please confirm how Enbridge Gas currently intends to satisfy its 2025 EPS obligation (payment of excess emissions charge versus EPUs) and the evaluation criteria it will apply.

b) If EPUs are procured, please provide details on quantity, purchase price, and the resulting impact on the total 2025 EPS compliance cost compared with the amount in evidence.

c) Please quantify the impact of the delay in adjusting the Facility Carbon Charge rate (following the federal carbon charge rate change to $0) on the 2025 variance.

Response:

a-b) Enbridge Gas intends on satisfying its 2025 EPS obligation through the purchase of Excess Emission Units from the Ministry of Environment Conservation and Parks (MECP) and does not intend to procure EPUs for its 2025 EPS obligation as the Premier of Ontario has suggested it may exempt EPS payments as a tariff relief measure in a letter to the Prime Minister dated August 17, 2026[1]. Should EPS payments be exempted for the 2025 year, EPU procurement from 3rd party sellers and the associated costs would be unnecessary and unlikely to be reimbursed by MECP or by the EPU sellers. As of October 29, 2026, EGI has not received information from MECP regarding EPS exemptions. EGI estimates a loss of potential savings of less than approximately $150,000 where it does not procure available EPUs for its 2025 EPS compliance obligation. Should EGI's 2025 EPS compliance

[1] https://x.com/I_stone/status/2091168105208946710?s=20

obligation be exempted prior to the December 1, 2026 deadline, then a purchase of EPUs could result in an unnecessary compliance instrument expense of up to approximately $1.2 million.

c) The Facility Carbon Charge applied on April 1, 2025 to June 30, 2025 was 0.0172 cents per cubic meter (¢/m^3) as approved by the OEB.[2] As of July 1, 2025, the Facility Carbon Charge was adjusted to 0.0123 ¢/m^3 as approved by the OEB[3] to account for the removal of the Federal Carbon Charge from company own use gas consumption that was previously included in the approved Facility Carbon Charge rate. The Facility Carbon Charge rate attributed to company own use gas was 0.0049 ¢/m^3 or approximately 28.5 percent of the April 1, 2025 Facility Carbon Charge rate. Between April 1, 2025 to June 30, 2025, Enbridge Gas collected $1.87 million in Facility Carbon Charges from customers, of which $0.53 million dollars was related to company own use carbon charges that were no longer applicable, and has been included in $0.74 million credit balance.

[2] EB-2024-0251, Decision and Order, February 28, 2025, pp.5-6.
[3] EB-2025-0078, Decision and Order, March 28, 2025, p.8.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 11, Earnings Sharing Mechanism Deferral Account
Exhibit B, Tab 1, Schedules 1 & 2

The Company achieved an ROE of 10.774%, resulting in gross over-earnings of $48.7 million and a $24.3 million credit (50/50 sharing) to ratepayers. Main drivers cited are colder weather and lower O&M costs (primarily compensation and benefits).

Question(s):

a) Please provide a more detailed breakdown of the weather impact (degree-day variance by month/quarter) and the resulting revenue impact that contributed to the over-earnings.
b) Please provide a detailed breakdown of the O&M underspend, with particular focus on compensation and benefits (actual vs. budget, key drivers of the variance).
c) Please confirm whether any one-time or non-recurring items (beyond those already adjusted) are included in the 2025 utility results used for the ESM calculation.
d) Please explain how the ESM amount will be allocated between the EGD and Union rate zones and across rate classes, and whether this is consistent with the methodology approved in the Phase 2 Settlement Agreement (EB-2024-0111).

Response:

a) Please refer to Table 1.

Table 1
2025 Weather – Delivery Margin Impact

Line No.	Month/Quarter	Actual HDD	Budget (Normal) HDD	Variance %	Colder/Warmer	Delivery Margin Impact ($ millions)
1	January	665	615	8%	Colder	15.4
2	February	579	559	4%	Colder	6.1
3	March	410	446	8%	Warmer	(11.4)
4	Quarter 1	1,654	1,620	2%	Colder	10.1
5	April	246	255	4%	Warmer	(2.6)
6	May	89	63	41%	Colder	9.4
7	June	5	-	100%	Colder	-
8	Quarter 2	341	317	7%	Colder	6.9
9	July	-	-	-	NA	-
10	August	5	-	100%	Colder	-
11	September	8	3	167%	Colder	0.6
12	Quarter 3	13	3	282%	Colder	0.6
13	October	141	144	-2%	Warmer	(0.8)
14	November	365	347	5%	Colder	5.4
15	December	602	510	18%	Colder	27.3
16	Quarter 4	1,108	1,001	11%	Colder	31.9
17	Total	3,116	2,941	6%	Colder	49.4

b) Please see Table 2 for detailed underspend O&M breakdown and drivers, on an budget vs actual basis.

Table 2
Utility O&M – 2025 Budget vs. 2025 Actuals

Line No.	Expense Categories	2025 Budget (Inflation Adjusted) ($M)	2025 Actual ($M)	2025 Budget vs. 2025 Actual $ Change	2025 Budget vs. 2025 Actual % Change
1	Compensation & Benefits	430.3	340.9	89.4	21%
2	Outside Services	271.1	250.0	21.0	8%
3	Materials and Supplies	32.3	32.2	0.0	0%
4	Professional and Regulatory Services	18.6	43.3	(24.7)	-133%
5	Other	61.0	69.7	(8.8)	-14%
6	Employee Related Services	5.0	2.3	2.7	55%
7	Repairs & Maintenance	4.6	6.5	(1.9)	-42%
8	Rents & Leases	13.5	12.7	0.8	6%
9	Travel & Accommodation	9.4	10.9	(1.4)	-15%
10	Donations & Memberships	5.3	1.1	4.2	80%
11	Internal Allocation & Recoveries	(21.4)	(63.1)	41.7	-195%
12	Energy Conservation	189.2	195.1	(6.0)	-3%
13	Central Functions	389.6	352.6	37.0	10%
14	Overhead Capitalization	(250.0)	(192.0)	(58.0)	23%
15	O&M settlement reduction - ($50M net, $68M gross)	(70.7)	-	(70.7)	100%
16	O&M Subtotal before adjustments	1,087.8	1,062.3	25.5	2%
17	Donations	-	(3.1)	3.1	
18	2025 DSMVA Correction	-	0.9	(0.9)	
19	Less write down of locates for 2023	-	(3.0)	3.0	
20	CF utility adjustment	-	(9.1)	9.1	
21	Total Unregulated/Non-Utility Eliminations		(14.3)	14.3	
22	Total Net Utility O&M Expense	1,087.8	1,048.0	39.8	4%

Compensation & Benefits (line 1): Actual expense was $340.9 million, $89.4 million below the inflation-adjusted budget of $430.3 million. The favourable variance reflects $24.7 million of lower benefit costs, driven by strong pension asset performance and lower pension expense, and $64.7 million of lower base

compensation, including $38.8 million of workforce-reduction savings and operational efficiencies delivered through optimization of work and resource plans.

Outside Services (line 2): Actual expense was $250.0 million, $21.0 million below budget. The favourable variance was primarily attributable to moving customer care collections and call-centre activities from an outsourced model to an in-house model, together with other operational efficiencies that offset inflationary pressures.

Professional and Regulatory Services (line 4): Actual expense was $43.3 million, $24.7 million above budget. The unfavourable variance comprised $10.0 million of external consulting costs, $10.0 million of affiliate flow-through costs that are fully recoverable through Internal Allocations and Recoveries, and a $4.7 million increase in intervenor and OEB assessment costs.

Other (line 5): Actual expense was $69.7 million, $8.8 million above budget. The variance primarily reflects incremental labour costs for work performed for affiliates and captured through time reporting; these costs are recovered through Internal Allocations and Recoveries.

Internal Allocation & Recoveries (line 11): Actual recoveries were $63.1 million compared with budgeted recoveries of $21.4 million, resulting in a $41.7 million favourable variance due to higher recoveries from affiliates.

Central Functions (line 13): Actual expense was $352.6 million, $37.0 million below the $389.6 million budget, reflecting efficiencies achieved across Central Functions.

Overhead Capitalization (line 14): Actual capitalization was $192.0 million compared with a budget of $250.0 million, resulting in a $58.0 million unfavourable variance. Of this amount, $50.0 million reflects the annual reduction required by the OEB's 2024 Rebasing Phase 2 rate order[1] from the $242 million approved in 2024, and $8.0 million reflects budget inflation.

O&M Settlement Reduction (line15): The budget included a $70.7 million reduction, while no separate actual amount was recorded because the committed reduction was achieved through the expense-category variances described above.

c) There are no other one-time or non-recurring items in the ESM calculation (other than those that have been adjusted for already in evidence).

d) The ESM deferral account balance is allocated to the EGD and Union rate zones in proportion to 2018 OEB-approved actual rate base. Within each rate zone, the

[1] EB-2024-0111, Draft Rate Order, November 4, 2024.

respective balances are allocated to rate classes in proportion to the rate base from the last OEB-approved cost allocation study for the EGD and Union rate zones.[2]

This methodology is consistent with the approach from the deferred rebasing term for annual proceedings for clearance of deferral and variance accounts and presentation of utility results and ESM amounts, as approved in the Phase 2 Settlement. [3]

[2] EGD rate zone as per EB-2017-0086, Exhibit G2, Tab 5, Schedule 1, line 8, columns (2-14). Union rate zones as per EB-2011-0210, Exhibit G3, Tab 2, Schedule 2, updated.
[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1,November 29, 2024, p.18.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 12, pg. 1, Dawn Parkway Surplus Capacity Deferral Account

In 2025, Enbridge Gas recognized $2.3 million of revenue from the sale of surplus capacity.

Question(s):

a) As seen in Table 1, volume went from 35,696 GJ/D from January to April to 51,098 GJ/D from May to December. What occurred between April and May that increased the volumes?
b) Is this volume expected to persist into 2026?
c) What is expected to happen to Dawn Parkway Surplus Capacity Deferral Account (Account No. 179-323) once the NPS 26 Trafalgar pipeline restriction is lifted?
d) Please provide the volume of surplus capacity sold in 2025, the unit rates achieved, and a reconciliation to the recorded revenue.
e) Please confirm whether Enbridge Gas evaluated any of this surplus capacity for potential PDO reduction prior to offering it for sale.

Response:

a) The change in volume in 2025 was due to amendments on existing M12 contracts for increased capacity, executed in 2023 but not effective until 2025.

b) The incremental volumes identified in part a) are expected to continue in 2026.

c) The impact on the Dawn Parkway Surplus Capacity Deferral Account of the NPS 26 restriction being lifted will depend on the timing of the removal of the restriction, and the demands on the Dawn Parkway system at that time.

d) The 2025 capacity increase of 15,402 GJ, sold in 2023, was transacted at the current OEB-approved M12 rate $4.098 resulting in an increase of monthly revenue of $ 0.063 million.

e) Due to the operational restriction on the Dawn to Parkway system, incremental shifts from Parkway to Dawn were not considered.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B (Utility Results)
Exhibit C, Tab 2, Schedule 12, Tax Variance Account

Enbridge Gas recorded a credit of $13.6 million almost entirely from the accelerated CCA available under the new Bill C-15 / Re-Accelerated Investment Incentive (RII) rules. These are temporary timing differences (larger CCA deductions in early years, offset by smaller deductions in later years) and do not represent tax savings.

Question(s):

a) Please confirm the treatment of any revenue requirement impacts arising from RII CCA changes in the 2025 Tax Variance Account and whether 100% of such impacts have been recorded for the benefit of ratepayers.
b) Please provide a summary of the qualifying capital additions places in service in 2025 that generated the accelerated CCA benefit.
c) Please provide a high-level summary of any other material tax rate or rule changes reflected in the 2025 Tax Variance Account balance.
d) Please confirm whether any energy transition or similar tax credits were recorded and how the sharing of the impacts is determined.

Response:

a) Confirmed. The $13.6 million payable to ratepayers passes on 100% of the RII CCA changes applied retroactively to 2025.

b) The summary of qualifying capital additions placed in service in 2025 is provided in Exhibit C, Tab 2, Schedule 12, Appendix 1, Column C which provides asset additions by class and as can be seen primarily pertain to distribution pipeline additions (line 19) plus compression assets (line 7) incurred during and placed into service in 2025.

c) No other tax rate or rule changes existed in 2025 that required recognition in the Tax Variance Account.

d) Enridge Gas did not claim any energy transition or similar tax credits in 2025.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 17, Indigenous Working Group Deferral Account
Exhibit G, Tab 3, Schedule 1
EB-2024-0125, Exhibit H, Tab 1, Schedule 2, Page 6 of 28
The 2025 balance is a debit of $0.269 million. Table 1 shows payments to participants (Brattle Group $124.2k, Resilient LLP $79.7k, etc.).

Question(s):

a) Please confirm the portion (if any) of the 2025 balance that relates to 2024 activity invoiced in 2025.

b) Please provide the estimated IWG spending for 2026 and compare it with the actual 2024 and 2025 costs. Explain any material changes in the composition of spending (legal support, consultants, First Nation representatives, experts).

c) Based on attendance and participation levels in 2025, please explain the rationale for any planned increases in consultant/First Nation representative funding and how additional funding will support rightsholder participation rather than consultants.

d) In Enbridge Gas's 2024 DVA proceeding it requested a budget of $800,000 for the year 2025. Please reconcile the proposed budget and the actuals and discuss any deviations.

Response:

a) Of the 2025 balance, $126,124 relates to the 2024 activities.

b) Estimated Indigenous Working Group (IWG) spending for 2026 is expected to be comparable to prior years. As the IWG continues to meet throughout the remainder of 2026, additional costs are expected to be incurred and invoiced before year-end. No material changes in the composition of spending are anticipated.

c) Enbridge Gas is not seeking an increase to the IWG budget at this time. Enbridge Gas continues to encourage direct participation by rightsholders and to identify opportunities to support their participation in the IWG. However, First Nations determine how they wish to participate, which may include designating a consultant or other representative to participate on their behalf. Where a First Nation chooses this form of representation, Enbridge Gas does not restrict participation on that basis. Accordingly, funding within the existing IWG budget provides flexibility to support First Nation participation in the manner determined by the participating First Nation.

d) The IWG established an estimated budget of $800,000 for 2025, which Enbridge Gas filed with the OEB for review. The OEB determined the budget should stay at the previously established $640,000 level, which has been used for purposes of the comparison to actuals in Table 1.

e) Actual 2025 expenditures were below the budgeted amount as we did not see an increase in participation from additional First Nations and their respective consultants, their legal support or experts.

Table 1
IWG Budget vs Actual Costs

Line No.	Particulars	2025 Budget	2025 Actual
1	Legal Support	$242,000	$88,254
2	Consultants and First Nations	$202,000	$23,013
3	Experts	$196,000	$31,190
4	Total	$640,000	$142,457

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 18, Average Use Variance Account

The net debit balance is $34.5 million. Several rate classes (Rate 1, M1, M2, 01, 10) experienced declines steeper than historical trends.

Question(s):

a) Please provide the weather-normalized average use actual vs. forecast by rate class and the resulting revenue impact calculation.
b) Please discuss the drivers of the steeper than historical declines observed in 2025 and whether Enbridge Gas expects these trends to continue.
c) Does Enbridge Gas expect these lower average use trends to persist into 2026 and beyond? If so what implications does this have for the forecast used in future IRM years or the next rebasing?

Response:

a) Please see Exhibit C, Tab 2, Schedule 18, Attachment 1, page 1 of 1, for the weather-normalized average use actual versus forecast by rate class and the resulting revenue impact calculation.

b-c) The steeper than historical declines in average use observed in 2025 may reflect changes in customer usage patterns (i.e. due to economic conditions, broader affordability concerns, and changes in technology, etc.) that may not be fully captured in the current forecasting process. Based on year-to-date 2026 results, lower average use has continued in some rate classes; however, it is too early to determine whether these declines represent a sustained trend that will persist beyond 2026. Enbridge Gas will continue to monitor average use and as additional actual data becomes available, Enbridge Gas will assess whether a new trend is emerging and, over time, use this information to support updates to future forecasts. As part of the next rebasing, the Company will review its forecasting process to determine whether any changes or updates are required.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 19, Getting Ontario Connected Act Variance Account
The balance is a debit of approximately $14.1 million (plus interest). ADD TABLE

Preamble:

Question(s):

a) Please explain how Enbridge Gas differentiates incremental locate costs directly attributable to Bill 93 / structural industry changes from other factors (inflation, volume, etc.).
b) Table 1 indicates the total locates to be on a downwards trend. Please discuss if this is trend is expected to continue.
c) Please confirm whether additional Locate Service Providers were onboarded in 2025 and the rationale.

Response:

a) As outlined at Exhibit C, Tab 2, Schedule 19, the 2025 locate budget of $53.1 million was derived by adjusting the 2024 base rate locate budget of $51.1 million by the applicable inflation and growth factors. Accordingly, inflation and growth are reflected in the 2025 budget used to determine the variance and are not separately included as incremental costs in the GOCA.

   The $14.1 million recorded in the GOCA represents the difference between the 2025 locate budget of $53.1 million and actual external locate costs of $67.2 million. As described in the evidence, Enbridge Gas's average unit cost for locating increased from approximately $32 in 2021, the pre-Bill 93 baseline used in the evidence, to more than double that amount following the implementation of the Bill 93 requirements. These requirements include the five-business-day locate delivery standard and the associated liability and administrative-penalty framework, which resulted in structural changes to the locate delivery market and increased the cost of external locate delivery. The methodology accounts for the inflation and growth

reflected in the 2025 budget before determining the incremental amount recorded in the GOCA.

Enbridge Gas has also continued to employ cost-reduction measures, including Alternative Locate Agreements and locate screening. These measures resulted in $12.1 million of estimated locating cost avoidance in 2025 and reduced the external locating costs that otherwise would have been reflected in the GOCA balance.

b) Enbridge Gas cannot reliably predict whether the recent downward trend in locate request volumes will continue. Locate request volumes are primarily driven by third-party excavation activity and therefore are not within Enbridge Gas's direct control. The volume of future locate requests will depend on the level and nature of excavation activity undertaken by third parties.

   Accordingly, Enbridge Gas does not consider the recent decline in locate volumes to be a sufficient basis to conclude that locate request volumes will continue to decline.

c) No additional Locate Service Providers were onboarded by Enbridge Gas in 2025.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 20, Disposition of Property Deferral Account
The ratepayers share of the net gain (50% of the capital gain net of capital gains tax) is grossed up to reflect the income tax deductibility/benefit provided by the amount returned to ratepayers. Proceeds from the disposition of depreciable assets such as buildings will be 100% to the benefit of ratepayers and the gain/loss is reflected in the combined balances of accumulated depreciation and the Site Restoration Cost Variance Account and are beyond the scope of this deferral account.

Question(s):

a) Please provide a list of all properties disposed of in 2025 that generated a record in the account including:
    a. Location of each property
    b. Original book value, accumulated depreciation and net book value.
b) Please confirm if the Site Restoration Cost Variance Account is the same account as Account 179-337.
c) Explain the allocation of the credits between the EGD and Union rate zones.

Response:

a) Please refer to Attachment 1 that provides the entries of each land property disposed of in 2025 and the respective breakdown between gross cost and accumulated depreciation for both the land and building portions of each transaction.

    As noted in Exhibit C, Tab 2, Schedule 20, page 1, each property was listed with details of the location of said property. This list is reproduced below:

    1. Brampton - Steeles Avenue West, west of Heritage Road and legally described as lands designated as Part 1 on 43R-41479, City of Brampton, Regional Municipality of Peel, Ontario
    2. Dryden - 304 Kennedy Road, Dryden, Ontario

3. Iroquois Falls – 209 Cambridge Road, Part Lot 12, Concession 4
4. Nipigon - 2 Wadsworth Drive, Nipigon, Ontario
5. Ottawa - 400 Coventry Road, Ottawa, Ontario
6. St. Thomas - 25 Sparling Road, St. Thomas, Ontario
7. Stratford - 827 Erie Street, Stratford, Ontario

b) Confirmed. However, it should be noted that although Enbridge Gas described in evidence that the benefit will be reflected in a combination of accumulated depreciation and Site Restoration Cost Variance Account (SRCVA), any residual gain or loss pertaining to buildings disposed of flows through and remains in accumulated depreciation. Residual gains are credited to accumulated depreciation and result in a decrease to rate base, whereas residual losses on buildings are debited to accumulated depreciation and result in an increase to rate base.

   Disposition of other depreciable property outside of buildings results in proceeds that flow through the SRCVA, however, there was no other depreciable property outside of buildings disposed of during 2025 as part of a property disposition transaction.

c) The allocation of the balance in the Disposition of Property Deferral Account (179-336) to the EGD and Union rate zones is by direct assignment based on the location of the property being disposed of. The allocation of the respective rate zone balances to rate classes is done in proportion to the allocation of distribution-related land gross plant costs from the last OEB-approved cost allocation study for the EGD and Union rate zones.

Disposition of Properties - 2025 Property Details

Line No.	Account	Property																					
		Brampton			Dryden			Iroquois Falls			Nipigon			Ottawa			St Thomas			Stratford			TOTAL		
		Land	Building	Total	Land	Building	Total	Land	Building	Total	Land	Building	Total	Land	Building	Total	Land	Building	Total	Land	Building	Total	Land	Building	Total
		(millions)																							
1	Gross Cost	$ 78,896	$ -	$ 78,896	$ 6,435	$ 146,928	$ 153,363	$ 74,995	$ 77,436	$ 152,431	$ 900	$ 208,205	$ 209,105	$ 87,874	$ 12,202,436	$ 12,290,310	$ 13,219	$ 548,070	$ 561,289	$ 22,121	$ 753,027	$ 775,148	$ 284,440	$ 13,936,102	$ 14,220,542
2	Accumulated Depreciation	$ -	$ -	$ -	$ -	$ (104,756)	$ (104,756)	$ -	$ (77,316)	$ (77,316)	$ -	$ (96,541)	$ (96,541)	$ -	$ (4,231,305)	$ (4,231,305)	$ -	$ (75,778)	$ (75,778)	$ -	$ (701,626)	$ (701,626)	$ -	$ (5,287,322)	$ (5,287,322)
3	Net Book Value	$ 78,896	$ -	$ 78,896	$ 6,435	$ 42,172	$ 48,607	$ 74,995	$ 120	$ 75,115	$ 900	$ 111,664	$ 112,564	$ 87,874	$ 7,971,131	$ 8,059,005	$ 13,219	$ 472,292	$ 485,511	$ 22,121	$ 51,401	$ 73,522	$ 284,440	$ 8,648,780	$ 8,933,220

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 21, LEAP Emergency Financial Assistance Deferral Account
Based on the LEAP EFA programs funding mechanism Enbridge Gas is required to contribute the greater of 0.12% of the Company's total OEB-approved distribution revenue requirement or $2,000 each year to LEAP EFA. Enbridge Gas contributed $4.7 million in total, which exceeded the base LEAP EFA funding requirement for 2025 of $3.5 million. In 2025, Enbridge Gas was required to add incremental funding of $1.2 million above the generic LEAP EFA funding requirement to ensure that no eligible LEAP EFA applicant was denied assistance due to lack of funding above the base 0.12% provided through generic funding.

Question(s):

a) Please provide the amount of LEAP funding embedded in 2024 and 2025 rates respectively and compare it to the actual incurred contributions in 2024 and 2025.
b) Please describe any changes to the LEAP design, selection criteria or demand that contributed to the variance.
c) Please provide rationale for the $1.2 million incremental funding described.

Response:

a) The amount of Low-income Energy Assistance Program (LEAP) funding embedded in 2024 rates was $3.3 million, compared to actual spending of $4.2 millon, resulting in a $0.8 million overage. Similarly, the amount of LEAP funding embedded in 2025 rates was $3.5M, compared to actual spending of $4.7 million, resulting in a $1.2 million overage.

b) Through its review of the LEAP Emergency Financial Assistance (EFA) program [1], the OEB announced changes to the LEAP EFA program to align it with the expanded Ontario Electricity Support Program[2]. These changes increased the maximum funding amount from $500 to $650 and stipulated that eligible applicants

[1] EB-2023-0135.
[2] EB-2023-0135, OEB Changes to LEAP EFA and Accounting Orders, February 12, 2024, p.2.

are not denied assistance due to funding limitations. In addition, demand for LEAP EFA assistance increased in 2025, with 7,584 customers receiving assistance compared to 7,316 customers in 2024. The average grant also increased, from approximately $496 per customer in 2024 to approximately $540 per customer in 2025. Together, these factors contributed to the increase in total LEAP EFA funding requirements and the variance between embedded funding and actual contributions.

c) The additional $1.2 million represents the difference between the 2025 LEAP EFA funding amount embedded in rates ($3.5 million) and the total funding required to support all eligible LEAP EFA applicants during the year ($4.7 million). Funding requirements increased in 2025 as both the number of customers receiving assistance and the average assistance provided per customer increased relative to 2024. In accordance with the OEB-approved LEAP EFA framework, Enbridge Gas provided the incremental funding above the base funding amount embedded in rates to ensure all eligible applicants received assistance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 22, OEB Cost Assessment Variance Account

For the years 2025 through 2028, this account records the variances in actual OEB Cost Assessment amounts incurred as compared to the $9.4 million that was included in the Company's 2024 O&M budget. The $9.4 million threshold will be adjusted each year using the IRM formula. Enbridge Gas will be entitled to recover any amounts that are more than $2 million above the annual threshold amount.

The balance recorded in the account is a debit of $2.997 million plus interest.

Question(s):

a) Please explain the primary drivers of the $3.0 million variance.

b) Are the OEB cost assessment expected to remain elevated into 2026 and into rebasing?

Response:

a) The primary driver of the $3.0 million variance is that the level of OEB Cost Assessment actually allocated to Enbridge Gas in the 2025 calendar year ($14.8 million) is approximately $5 million more than what Enbridge Gas had forecasted in its 2024 Rebasing Phase 1[1] application ($9.4 million escalated in 2025 to $9.8 million).

b) Yes, it is expected that the OEB Cost Assessment will remain elevated into 2026 and into 2029 rebasing.

This is based on Enbridge Gas' assessment of:

1. The current level of OEB Cost Assessment in calendar 2026 ($15.8 million), and

[1] EB-2020-0200.

2. The OEB 2025-2028 Business Plan[2] which indicates that the level of OEB Cost Assessment overall to all utilities is expected to grow by approximately 6.2% for the 2026/2027 assessment year and by a further 2.6% for the 2027-2028 assessment year.

[2] Ontario Energy Board Business Plan 2025-2028, p.33.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 23, pp. 1-3
Exhibit C, Tab 2, Schedule 24, pp. 6-7

Enbridge Gas requests clearance of $0.388 million plus interest in the IRP System Pruning Deferral Account.

Enbridge Gas does not request clearance of the $2.2 million in cumulative operating costs recorded in the IRP Operating Costs Deferral account attributable to the Southern Lake Huron (SLH) Pilot Project, given the OEB's previous finding (EB-2025-0155) that it is premature to consider costs for the SLH Pilot Project as it is not sufficiently advanced to determine if it is appropriate for ratepayers to pay the costs incurred, and that Enbridge Gas can seek disposition when it is in a position to report on the results from the project.

Question(s):

a) What factors support clearance of the System Pruning pilot costs at this time, given that the System Pruning pilot is at an early stage and given the OEB's findings on the SLH Pilot Project costs?
b) Please provide a high-level breakdown of SLH Pilot Project costs in 2025.
c) Please provide a forecast of annual costs for the SLH Pilot Project in 2026 and future years.
d) Does Enbridge Gas anticipate being able to report on results and seek disposition of SLH Pilot Project costs in the 2026 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding? Why or why not?

Response:

a) The System Pruning costs proposed for clearance were incurred for foundational activities required to inform the pilot approach and interest level of potential candidates as opposed to costs for the field implementation of a pilot project, and these foundational activities have been completed. Enbridge Gas has reported the

results for these activities, which have been filed and/or posted publicly on the OEB natural gas Integrated Resource Planning (IRP) webpage. The costs filed for clearance are specific to these foundational activities which include the jurisdictional scan, customer research, and implementation of the pre-screen form to identify the interest level of potential pilot candidates, as well as the associated incremental staffing costs to execute System Pruning requirements.

The completed reports and results for these foundational activities are provided:

i) Jurisdictional scan – the link to the completed report was filed in the 2025 IRP Annual Report at Exhibit G, Tab 2, Schedule 1, page 24, footnote 22
   - Jurisdictional scan report link

ii) Customer research – the reports were filed in the 2024 IRP Annual Report Appendix G: System Pruning Pilot Approach Appendix 2 and 3.[1]

iii) Pre-screen form – the outcomes from pre-screen form implementation are summarized in the 2025 IRP Annual Report[2]. The pre-screen form, as well as reported results discussed with the IRP Technical Working Group (TWG) at Meeting 61, are posted on the OEB Natural Gas IRP webpage at the following links:
   - Pre-screen form link
   - IRP TWG Meeting 61 link

The milestone conditions of the Settlement Proposal have been met, as outlined in Exhibit C, Tab 2, Schedule 23, pages 1-2, and these foundational activities were described in the System Pruning Pilot Approach filed as Appendix G in the 2024 IRP Annual Report.[3] The IRP TWG supported proceeding with this approach subject to ongoing review and further input,[4] and has continued to be consulted to inform these foundational activities.

A subcommittee of the IRP TWG was established to support detailed consultation on the jurisdictional scan and System Pruning approach, with the full IRP TWG engaged at key milestones. The full IRP TWG provided feedback on the scope of the jurisdictional scan, while the subcommittee reviewed the jurisdictional scan, customer research discussion guide and survey language. The pre-screen form was subsequently shared with the full IRP TWG for their review to inform the questions.

[1] EB-2025-0064, Exhibit I.1.13-ED-4, Attachment 1, Appendix 2 and 3, pp.135 – 237.
[2] Exhibit G, Tab 2, Schedule 1, p. 24.
[3] EB-2025-0064, Exhibit I.1.13-ED-4 Attachment 1, pp.108 - 237
[4] EB-2025-0064, Exhibit I.1.13-ED-4 Attachment 1, p.110

b) Table 1 provides the breakdown of the 2025 costs.

Table 1

Breakdown of 2025 Expenditures – SLH Pilot Costs

Line No.	Item	Description	Millions ($)
1	Incentives	Financial incentives to customers	0.215
2	Promotion and Delivery	Offer promotion and market delivery	0.685
3	Incremental Staff	Salaries, loadings and expenses	0.799
4	Administrative/Legal	OEB hearing process and legal support	0.125
5	Pilot Learning Costs	Data collection and analysis	0.298
6	Total		2.123

c) The table below is a high-level forecast of annual costs in 2026 and 2027 for the Southern Lake Huron (SLH) Pilot Project. Actual costs will be reported in future Utility Earnings and Disposition of Deferral & Variance Account Balances proceedings.

Table 2

Forecast – SLH Pilot Costs

Line No.	Item	2026 Millions ($)	2027 Millions ($)
1	Incentives	6.869	0.035
2	Promotion and Delivery	1.409	0.035
3	Incremental Staff	0.892	0.700
4	Administrative/Legal	0.062	0.050
5	Pilot Learning Costs	0.611	0.169
6	Total	9.842	0.988

d) Yes, Enbridge Gas anticipates being able to seek disposition of SLH Pilot Project costs in the 2026 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding.

Field implementation of the following SLH Pilot offers will have ended by December 31, 2026:

- Residential Whole Home Custom
- Residential Single Measure Attic Insulation
- Residential Limited Electrification
- Commercial and Industrial Direct Install
- Commercial and Industrial Prescriptive Downstream
- Commercial and Industrial Custom

Enbridge Gas will be able to report on the implementation and participation in the offers. Interim evaluation reports for the SLH Pilot Project objectives will also be available at that time. Enbridge Gas considers this to be sufficiently advanced to clear related costs and meet the OEB's previous finding that Enbridge Gas can seek disposition when it is in a position to report on the results from the project.

The SLH Pilot Project Residential Demand Response offer ends following the close of Q1 2027 and pilot evaluation activities are expected throughout 2027. Enbridge Gas expects to seek disposition of the final SLH pilot-related costs in the 2027 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit C, Tab 1, Schedule 1
Exhibit C, Tab 2, Schedule 24, Accounts Not Being Requested for Clearance
Several accounts have material balances that are not being requested for clearance (e.g., IRP Operating Costs $2.3 million, Panhandle Region Expansion Project $10.8 million credit, Site Restoration Costs $15.6 million credit).

Question(s):

a) For each of the accounts that have balances and are not being requested to be disposed, please provide the expected timing of future disposition requests.

b) For each of the accounts, are the balances expected to continue to accrue in the same manner (and similar magnitude) as they have to date? If not, please explain the expected changes in the nature or magnitude of future accruals.

Response:

a) See below for the expected timing of future disposition requests:

1. Integrated Resource Planning (IRP) Operating Costs – As noted in Exhibit I.STAFF-13, Enbridge Gas anticipates being able to seek disposition of Southern Lake Huron (SLH) Pilot Project costs in the 2026 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding.

2. Panhandle Region Expansion Project – as noted in Exhibit C, Tab 2, Schedule 24, page 9:

> This variance will accumulate in the account and the net residual amount will be brought forward in Enbridge Gas's next rebasing application for disposal.

It is therefore expected that Enbridge Gas will bring the relevant net residual balance forward with its 2029 Rebasing application.

3. Site restoration Costs – as noted in Exhibit C, Tab 2, Schedule 24, page 13:

   > The balance in the account will not be brought forward for annual disposition since the purpose of the funds is to offset future decommissioning, abandonment, or site restoration.

   Therefore, the account is considered a tracking account that reflects the cumulative life to date (since January 1, 2024) amount of site restoration costs recovered through depreciation, plus cumulative investment income earned net of tax, offset by annual actual costs of site restoration incurred.

b) See below for expectations of each account:

1. IRP Operating Costs – the balance noted pertains specifically to the cumulative costs of the SLH Project and it is expected that Enbridge Gas will continue to accrue operating costs related to ongoing operations related to that project, adding to the cumulative balance that will be brought forward in the 2026 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding. Refer to Exhibit I.STAFF-13 for further details.

2. Panhandle Region Expansion Project – as noted Exhibit C, Tab 2, Schedule 24, page 9:

   > This account records the difference between the actual net revenue requirement for the Panhandle Regional Expansion Project (PREP) and the actual revenues collected through the levelized PREP unit rate approved by the OEB.

   Therefore, it is expected that as Enbridge Gas continues collecting the levelized rate through the remaining IR term, the net cumulative gap between actual cumulative revenue requirement and revenues collected will shrink through the end of 2028.

3. Site Restoration Costs – in general, yes, the account is expected to operate in the manner described and accumulate over an indefinite period.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit G, Tab 1, Schedule 3, pp. 18, Estimated Billing and Meter Reading Performance Report

In its EB-2025-0155 Decision and Order regarding the 2024 DVA proceeding, the OEB directed Enbridge Gas in its next DVA proceeding to provide a detailed report on the measures it has taken to address the OEB's ongoing concern about estimated customer bills.

Enbridge Gas noted that it remains committed to improving meter reading performance and will continue to evaluate opportunities to further reduce consecutive estimates. Enbridge Gas further noted that its experience since 2022 suggests that a significant portion of the remaining MRPM population is driven by customer access and other external factors and that Enbridge Gas remains unable to meet the MRPM.

Enbridge Gas stated that it will address this further with the OEB, likely through a request that the OEB Chief Executive Officer convene a review of GDAR to consider whether and how the MRPM target should be re-set. Alternately, Enbridge Gas stated that it may file an application or request an exemption from the MRPM target for 2026 and beyond as it continues with its implementation of AMR and ERT technologies and its AMI implementation plan.

Question(s):

a) Has Enbridge Gas determined the next steps it intends to take to address its inability to meet the MRPM?
    a. If yes, please explain the planned actions and provide the associated timelines or target dates.
    b. If not, please discuss when Enbridge Gas will determine the next steps.

b) Please describe any other options and considerations that Enbridge Gas evaluated to address its inability to meet the MRPM.

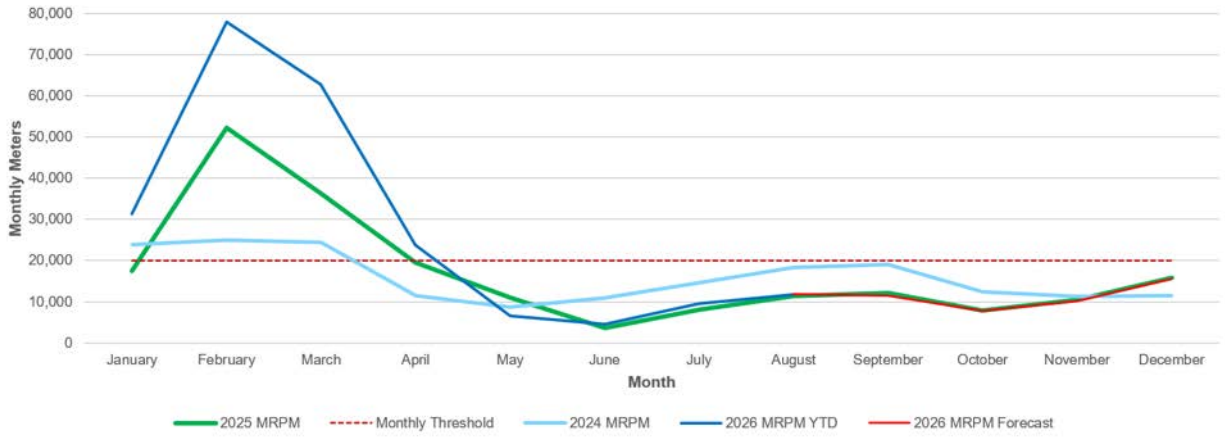
Response:

a) Yes, Enbridge Gas will continue to pursue initiatives intended to improve meter reading performance and reduce consecutive estimated bills. These initiatives include ongoing outreach to customers with inaccessible meters to obtain customer-provided reads, continued deployment of Advanced Meter Reading (AMR) and Encoder Receiver Transmitter (ERT) technologies where feasible and targeted meter replacement activity in communities that have historically experienced elevated numbers of consecutive estimated bills.

In addition, Enbridge Gas is reviewing the methodology used to calculate and report Meter Reading Performance Measurement (MRPM) results. Based on its experience since 2022, Enbridge Gas believes a significant portion of the remaining MRPM population is attributable to inaccessible meters and other factors outside of Enbridge Gas' direct control. Accordingly, Enbridge Gas is discussing a revised reporting methodology that would address situations where the same inaccessible meter is counted in multiple reporting periods after reaching the consecutive estimate threshold.

Enbridge Gas continues to evaluate this approach and may seek implementation of a revised methodology (Table 1) through an appropriate regulatory process if it determines that such changes are warranted.

Table 1
MRPM Performance vs Metric Limit (Alternative Calculation)



b) Enbridge Gas evaluated a range of options to improve meter reading performance, including expanded customer outreach, increased use of customer submitted meter readings, continued deployment of AMR and ERT technologies, targeted meter replacement activity in areas with historically elevated numbers of consecutive

estimated meter readings and the continued exploration of Advanced Metering Infrastructure (AMI) technology.

Enbridge Gas also evaluated the extent to which factors outside of its direct control contribute to MRPM performance, including inaccessible meters, customer availability, weather-related access challenges and seasonal operating conditions. Based on Enbridge Gas' experience since 2022, a significant portion of the remaining MRPM population is attributable to these factors. This assessment informed Enbridge Gas' proposal to review and revise the current MRPM reporting methodology.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, p. 4
Exhibit B, Tab 1, Schedule 5, p. 4
Exhibit B, Tab 3, Schedule 1, p. 3

Question(s):

a) Please further describe the depreciation error that was identified in Q2 2026.

b) Please advise precisely where the depreciation error-related adjustments were made in Exhibit B, Tab 1, Schedule 5 (Continuity of Accumulated Depreciation).

c) Please explain the overall impact (including both the increase to PP&E and decrease to depreciation expense) of the correction to the depreciation error on the earnings sharing calculation.

Response:

a) Please refer to Exhibit I.SEC-2 part a).

b) The depreciation error-related adjustments were recorded to the Software Acquired/ Developed Account (491), as presented in Exhibit B, Tab 1, Schedule 5, page 4, line 39. Specifically, the 2024 depreciation error of $14.5 million was included as an opening balance adjustment in Column 1, and the 2025 depreciation error of $2.8 million was reflected in Column 6, “Adjustments & Other.”

c) The depreciation error-related adjustments resulted in both higher net PP&E and lower depreciation expense. The decrease in depreciation expense increased utility income used in the 2025 earnings sharing calculation, thereby increasing the earnings sharing credit to ratepayers. At the same time, the increase in net PP&E increased average rate base and deemed common equity, which lowered the achieved ROE used in the earnings sharing calculation and reduced the earnings sharing credit. The impact of the higher utility income was greater than the impact of the higher rate base, resulting in a net $2.6 million increase to the 2025 gross sufficiency and a $1.3 million increase to the earnings sharing credit to ratepayers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 3, p. 1
Exhibit C, Tab 2, Schedule 12, p. 3 and Appendix 1, p. 1

Question(s):

a) Please explain the "2025 TVDA adjustment to reflect retroactive Bill C-15 enacted in 2026" adjustment referenced in Exhibit B, Tab 1, Schedule 3.

b) Please further explain the statement that RII property is not subject to the half-year rule (Exhibit C, Tab 2, Schedule 12, p. 3) and explain the implications of this treatment on the adjustment made to the earnings sharing calculation. As part of the response, please advise whether the half-year rule was applied for CCA purposes when establishing base rates.

Response:

a) As noted in Exhibit C, Tab 2, Schedule 12, Plus Appendix, page 1 of 4: On March 26, 2026, Bill C-15 (Budget 2025 Implementation Act, No. 1) received Royal Assent and is now enacted legislation. Subsequent to Enbridge Gas's year end and filing of audited financial statements for the year ended December 31, 2025, the enactment of Bill C-15 resulted in a retroactive application of the impact of the Reaccelerated Investment Incentive (RII) provisions. As a result, qualifying 2025 capital additions were eligible for accelerated Capital Cost Allowance (CCA) deductions that were not reflected in the tax assumptions underlying 2025 Corporate results presented in Exhibit B, Tab 1, Schedule 7, page 1 of 1, Col. 1 and Col. 2 and in Exhibit B, Tab 1, Schedule 3, page 1 of 1, Column 1. Accordingly, Enbridge Gas reflected the enactment of Bill C-15 which resulted in lower current income taxes payable in 2025 than would have occurred under the CCA rules assumed in rates.

   Consistent with the OEB's accounting direction regarding accelerated CCA incentives, Enbridge Gas recorded the incremental tax benefit arising from the retroactive application of Bill C-15 in the Tax Variance Deferral Account (TVDA). The adjustment included in the utility earnings calculation removes the impact of this

retroactive legislative change such that 2025 utility earnings are determined on a basis consistent with the tax assumptions reflected in rates.

In order to reflect the benefit of the lower utility income tax in 2025 through the TVDA, EGI recognized the appropriate entry that credited the TVDA for the $13.6 million dollar deferral impact offset by a reduction to utility earnings effectively nullifying the lower income tax impact since ratepayers receive the benefit through the refund in the TVDA.

b) Under the RII provisions enacted through Bill C-15, qualifying property is not subject to the half-year rule. As a result, 100% of the capital cost of eligible additions is included in the CCA calculation in the year the asset becomes available for use, rather than only 50% of the net addition being eligible for first-year CCA under the traditional half-year rule.

For purposes of the earnings sharing calculation, the impact of the RII provisions was isolated by comparing the CCA deduction permitted under the enacted RII rule; and the CCA deduction that would have been available under the tax rules reflected in rates.

The resulting incremental CCA deduction reduced 2025 income taxes (as included in Exhibit B, Tab 1, Schedule 3, page 1 of 1, line 14, Col. 4) and therefore increased reported utility earnings. Since this benefit arose from a retroactive legislative change and was recorded to the TVDA for future disposition to ratepayers, the corresponding TVDA adjustment was reflected as an adjustment to utility earnings to remove the impact of the RII benefit from earnings subject to earnings sharing (as included in Exhibit B, Tab 1, Schedule 3, page 1 of 1, line 1, Col. 3 & 4).

The half-year rule was not applied in determining the CCA assumptions reflected in rates. The tax assumptions underlying rates already reflected the accelerated CCA framework introduced under Bill C-97, which similarly suspended the half-year rule for qualifying property. It was Bill C-15 that allowed for further accelerated CCA deductions beyond a continued suspension of the half-year rule, and made available through the RII provisions enacted and applied retroactively to qualifying 2025 additions.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

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

Preamble:

Compensation and Benefits (line 1) decreased by $105.4 million, primarily driven by the absence of $48.3 million in one-time 2024 severance costs and a $37.0 million reduction in pension expense.

Question(s):

Please explain the driver of the remaining approximate $20 million decrease to compensation and benefit costs.

Response:

The remaining $20 million decrease in Compensation and Benefits costs is primarily attributable to lower salaries and benefits from vacancies, the full-year impact of the 2024 workforce reduction, and operational efficiencies delivered through optimization of work and resource plans.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

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

Preamble:

Professional and Regulatory Services (line 4) increased by $17.0 million, mainly due to (i) $10.0 million external consulting costs, and (ii) $10.0 million of affiliate flowthrough costs, fully recoverable through Internal Allocations and Recoveries (line 11).

Question(s):

Please further describe the “affiliate flow-through costs” and explain why these affiliate-related costs are driving increased regulated costs that form part of the earnings sharing calculation.

Response:

Affiliate flow-through costs include consulting work paid through Enbridge Gas Ontario on behalf of Enbridge affiliates. These costs do not increase regulated costs included in the earnings sharing calculation, as they are flowed through and recovered through line 11, Internal Allocations and Recoveries.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 8, p. 3
EB-2025-0155, Exhibit I.CCC-1

Question(s):

Please provide updated versions of Tables 1 and 2 to EB-2025-0155, Exhibit I.CCC-1 showing the calculation of the 2025 regulated and unregulated facility-related obligation cost allocations.

Response:

Enbridge Gas has identified a mistake related to the regulated 2025 Emissions Performance Standards (EPS) compliance obligation[1], resulting in a difference of $0.016 million., which if corrected would result in a reduction of the credit balance to ratepayers from $0.74 million to $0.72 million in the Facility Carbon Charge Variance Account, as provided in Exhibit C, Tab 1, Schedule 8. Enbridge Gas does not intend to correct this mistake.

Table 1 provides the calculation of the 2025 regulated and unregulated EPS compliance obligation using the uncorrected compliance obligation costs, that tie to the evidence provided in Exhibit C, Tab 1, Schedule 8.

[1] The correct 2025 regulated EPS compliance amount is $6.08 million (line 10), resulting in an unregulated EPS compliance amount of $1.59 million (line 11), with a total regulated facility related cost of $7.16 million (line 12), and total unregulated facility related cost of $ 1.59 million (line 13).

Table 1
2025 Summary of Facility-Related Costs

Line No	Particulars	Jan – Mar 2025	
1	Company Use Volumes – regulated (10^6m^3)	7.09	
2	Company Use volumes – unregulated (10^6m^3)	0.006	
3	Federal Carbon Charge Rate ($/$m^3$)	0.1525	
4	Company Use Costs – regulated ($millions) (line 1 x line 3)	1.08	
5	Company Use Costs – unregulated ($millions) (line 2 x line 3)	0.00	
6	Company Use Costs – total ($millions) (line 4 + line 5)	1.08	
7	EPS Compliance Obligation (tCO_{2e})		80,792
8	Excess Emissions Charge ($/$tCO_{2e}$) (1)		95.00
9	EPS Compliance Obligation Costs – Total ($millions) (line 7 x line 8)		7.68
10	EPS Compliance Obligation Costs - Regulated ($millions)(2)		6.06
11	EPS Compliance Obligation Costs - Unregulated ($millions) (3)		1.61
12	Total Facility Related Costs - Regulated ($millions) (line 4 + line 10)		7.14
13	Total Facility Related Costs - Unregulated ($millions) (line 5 + line 11)		1.61
14	Total Facility Related Costs ($millions) (line 12 + line 13)		8.75

Notes:
(1) Emissions Performance Standards Regulation, O.Reg. 241/19, Section 11.1
(2) Regulated EPS costs are allocated based on regulated/unregulated total EPS volumes (see Table 2)
(3) Totals may not sum due to rounding

Table 2
2025 Facility-Related EPS Volumes[1]

Line No.	Particulars	Actuals
1	EPS Volumes - Regulated (10^3m^3)	129,027
2	EPS Volumes - Unregulated (10^3m^3)	33,215
3	EPS Volumes (10^3m^3)	162,242

Notes:
(1) EPS volumes for January 1 to December 31, 2025.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 10, p. 3
EB-2025-0155, Exhibit I.CCC-2

Question(s):

Please provide an updated version of Table 1 to EB-2025-0155, Exhibit I.CCC-2 showing the calculation of the 2025 carbon charge-related bad debt. As part of the response, please advise whether any methodological changes were made to the determination of the balance in the account.

Response:

a) The calculation of carbon bad debt for the time period in which the federal carbon charge was in place used the methodology shown in Table 1 EB-2025-0155, Exhibit 1.CCC-2. The amount of carbon related bad debt for the period of January to March 2025 is shown in Table 1 below, columns (a) through (e).

   The carbon bad debt amounts for April 2025 onwards after the federal carbon charge was stopped are related to the 2025 EPS, billing adjustments and true-ups, and are shown in Table 1, column (f), with the 2025 total carbon related bad debt shown in column (g).

Table 1
2025 Carbon Charge Bad Debt

Line No.	Rate Zone	2025 Consumer Carbon Charges billed Jan - March 2025 ($ millions)	2025 Company Revenue Jan to March 2025 (including FCPP charges) ($ millions)	Jan to March 2025 % of bill related to Consumer Carbon Charges	Jan to March 2025 Company Bad Debt ($ millions)	Jan to March 2025 Carbon Bad Debt ($ millions)	Other Carbon Bad Debt ($ millions)	2025 Carbon Bad Debt ($ millions)
		(a)	(b)	(c) = (a/b)	(d)	(e) = (c*d)	(f)	(g) = (e + f)
1	EGD	882.5	2,497.4	35.3%	10.85	3.83	0.39	4.22
2	UGL	489.0	1,449.9	33.7%	6.51	2.20	0.53	2.73
3	EGI total					6.03	0.92	6.95

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 15, Attachment 1
Exhibit B, Tab 1, Schedule 3, p. 1

Question(s):

Please explain how the 2025 PTUVA credit of $49.0 million is treated from an earnings sharing perspective (including a reference to where it is reflected in the earnings sharing calculation). As part of the response, please also advise whether ratepayers receive a share of the amount retained by Enbridge Gas in 2025 through the application of the $10 million deadband.

Response:

As noted in Exhibit C, Tab 2, Schedule 15, Attachment 1, prior to determination of the required Post-Retirement True-Up Variance Account (PTUVA) credit, Enbridge Gas in its Corporate results reflected a $49.7 million sufficiency pertaining to its recognized net periodic benefit cost plus related income tax impacts. After comparing this revenue sufficiency to the sufficiency embedded in approved rates for 2025, Enbridge Gas calculated a $43.4 million net sufficiency grossed up to $59.0 million for taxes. After adjusting for the approved $10 million deadband, the resulting $49.0 million payable to ratepayers was calculated and recorded through the following journal entry in accordance with the approved accounting order: debit Account No. 300 - Operating Revenue and credit Account No. 179-328 – Post-Retirement True-up Variance Account.

As a result of the above entry, the $49.0 million PTUVA payable is removed from utility results and credited to ratepayers, leaving the remaining $10.0 million grossed up sufficiency included in utility results and subject to earnings sharing.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 20, pp. 1-3 and Attachment 1

Preamble:

This account records 50% of the grossed-up after-tax gain/loss resulting from the disposition of non-depreciable land.

Enbridge Gas allocates proceeds between land and building based on independent broker evaluations or comparable valuation evidence that reflects the fair value of each component within the overall transaction on a sale by sale basis. Broker evaluations provide an objective, market-based assessment of the relative value of land and building components.

Proceeds from the disposition of depreciable assets such as buildings will be 100% to the benefit of ratepayers and the gain/loss is reflected in the combined balances of accumulated depreciation and the Site Restoration Cost Variance Account and are beyond the scope of this deferral account.

Question(s):

a) Please confirm that this is the first year that the DPDA has recorded a balance for disposition.
b) Please further explain the methodology used to pass-through to ratepayers 100% of the benefit of proceeds from the disposition of depreciable property (as between assignment to accumulated depreciation and the SRCVA). As part of the response, using Stratford (Attachment 1 / Column (g)) as an example, explain the accounting of the sale proceeds as between: (i) the DPDA for land; and (ii) accumulated depreciation and the SRCVA for the related building. Please also provide a reference to where in the application the proceeds from the Stratford building sale are shown.
c) For each sale listed in Attachment 1, please provide documentation (i.e., broker evaluations or comparable valuation evidence) supporting the allocation of sale proceeds between land and buildings.

Response:

a) Confirmed.

b) The treatment of depreciable property ensures that 100% of the proceeds, and therefore any resulting gain or loss on disposition, is reflected for the benefit of ratepayers. The specific accounting treatment depends on the nature of the depreciable property.

For buildings, the proceeds allocated to the building are reflected through accumulated depreciation as a credit. Upon disposition, the original cost of the building is removed from gross plant, the accumulated depreciation recorded to date is removed, and the proceeds attributed to the building are reflected in determining the residual amount remaining in accumulated depreciation. Accordingly, any residual gain is credited to accumulated depreciation, thereby reducing the amount to be recovered from ratepayers through future depreciation rates, while any residual loss is debited to accumulated depreciation and represents the remaining investment to be recovered through future depreciation after reflecting the applicable proceeds.

For other depreciable property, the disposition proceeds would be reflected through the Site Restoration Cost Variance Account (SRCVA). Accordingly, these proceeds would also be captured for ratepayers rather than being recognized as a gain retained by the shareholder. Note that there is no applicable other depreciable property disposed of during 2025. The only applicable depreciable property in 2025 was buildings.

Regarding the example of the Stratford property disposition, please see Table 1 for the details of the transaction recorded.

Table 1
Stratford Property Disposition

Line No.	Particulars	Allocation of Proceeds (net of closing costs)	Net Book Value (Gross Cost less Accumulated Depreciation)	Gain on Sale	Gain Recognized To
1	Land	$1,289,774	$22,121	$1,267,653	50% Other Income / 50% DPDA
2	Building	$606,952	$51,401	$555,551	Accumulated Depreciation

With regard to the proceeds of each transaction, see below in relation to the split between proceeds for land and building:

- Land – ultimately reflected in Exhibit B, Tab 1, Schedule 3, Line 5, Col. 1 as part of the calculation of the net gain
- Building – reflected in accumulated depreciation and shown in EB-2026-0108 Exhibit B, Tab 1, Schedule 5, page 4 of 5, Line 17, Col. 4 as part of Costs Net of Proceeds

c) Please refer to the response at Exhibit I.SEC-5 for documentation supporting the allocation of sale proceeds between land and buildings.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

EB-2025-0064, Exhibit 2, Tab 7, Schedule 2
EB-2025-0064, Exhibit I.2.7-CCC-2
Exhibit G, Tab 1, Schedule 3, pp. 16-18

Preamble:

In EB-2025-0064 at Exhibit I.2.7-CCC-2, Enbridge Gas stated that it intends to develop a plan for large-scale AMI implementation, but that plan will be influenced (and could be changed) by the results of the Proof of Concept (POC).

Enbridge Gas also confirmed that it will provide details of its plans for large-scale AMI deployment to the OEB at or before the time that the Company proceeds with any such project.

In the current proceeding, Enbridge Gas stated that it may file an application or request an exemption from the MRPM target for 2026 and beyond as the Company continues with its implementation of AMR and ERT technologies and its AMI implementation plan.

In addition, Enbridge Gas noted that more than 148,000 AMR meters have been installed since January 2025, with deployment prioritized in areas experiencing known accessibility challenges.

Question(s):

a) Please advise whether the AMI POC has been completed. If not, please provide the expected completion date. If so, please provide the findings resulting from the POC and the cost-benefit analysis that Enbridge Gas stated “will be completed by the end of the POC.”1
b) Please advise whether the AMI implementation plan has been completed. If so, please file documentation associated with the implementation plan on the record.
c) If the AMI implementation plan is not yet completed, please provide any initial details regarding AMI implementation including the forecast cost, the forecast cost per meter, the number of meters to be installed, and potential timing.

d) Please advise whether the installation of 148,000 AMR meters forms part of the Company's AMI implementation plan. If not, please explain.

e) Please provide the costs (broken down between capital and operational costs) associated with the installation of 148,000 AMR meters. As part of the response, please confirm that the costs associated with the installation of these meters is reflected in the earnings sharing calculation.

f) Please provide additional details regarding the need for the installation of 148,000 AMR meters. As part of the response, please advise:
   - whether these meters were installed as replacements for existing meters (or installed for new customers)
   - whether the existing meters were at the end of useful life
   - whether the existing meters were damaged or otherwise unusable

Response:

a) Significant work has been completed as part of the POC, with the initial field component completed in early 2026. Enbridge Gas is continuing its review and analysis of the POC results to date. Further investigation and validation may be undertaken as Enbridge Gas evaluates potential AMI solutions and develops its implementation plan. The cost benefit analysis will be completed before the Company proceeds with full Advanced Metering Infrastructure (AMI) deployment.

   Learnings to date from the POC relate to AMI meter and network functionality, including:

   - On demand two-way communication
   - Consumption history
   - Meter theft detection
   - Remote meter disconnection
   - Safety alarms (High Flow, High Temperature, High Pressure, Low Pressure, Air in Pipe)

   These learnings are preliminary and will be considered together with the cost-benefit analysis in developing the AMI implementation plan.

b) The AMI implementation plan has not been completed. See section c) below for further information.

c) Enbridge Gas's plan is to continue the investigation and feasibility phases of the AMI implementation plan through 2026 and 2027, with the possibility that AMI deployment could begin in 2028. The forecast costs, cost per meter, number of meters to be installed, and specific deployment timing have not been finalized.

d) No. The installation of AMR (Automated Meter Reading) meters is not part of the Company's AMI implementation plan. AMR and AMI are different technologies.

   Enbridge Gas purchases and installs AMR-capable meters through its ongoing meter programs and existing work activities. AMR-capable meters were also purchased when conventional diaphragm meters become difficult to procure due to manufacturer and broader supply-chain constraints.

   AMR and other remotely readable meter technologies such as Encoder Receiver Transmitter (ERT) provide one-way remote collection of meter consumption data which can help mitigate meter access and weather-related meter reading challenges. AMI provides two-way communications and additional functionality as described in part a). Accordingly, the installation of AMR-capable meters does not constitute deployment of the AMI solution being evaluated through the Company's AMI POC and implementation planning.

e) Capital expenditures associated with the purchase and installation of the approximately 148,000 AMR-capable meters are included within the Utilization capital expenditures reported in Table 2 at Exhibit B, Tab 3, Schedule 2. Related meter-reading operating costs are included within the Utility Operating and Maintenance expenditures reported in Table 1 at Exhibit B, Tab 3, Schedule 1.

   AMR-capable meters have a higher initial purchase cost than comparable conventional diaphragm meters. As described in previous Asset Management Plans, Enbridge Gas purchased ultrasonic meters as a substitute when diaphragm meters became increasingly difficult to procure due to manufacturer and broader supply-chain constraints.

   There is no material difference in installation labour or ongoing operating costs for AMR-capable meters compared with conventional diaphragm meters, as meter readings must continue to be obtained whether through conventional field visits or remotely using handheld devices.

f) The approximately 148,000 AMR meters were not installed through a standalone mass deployment program. Enbridge Gas purchases AMR meters, along with conventional diaphragm meters, as part of its annual meter requirements. AMR meters were installed where a meter was required through existing work activities including installations for new customers, government exchange programs, meter

upgrades or downgrades, alterations and circumstances involving meter reading or access challenges.

Accordingly:

i. The AMR meters include both meters installed for new customers and meters installed as replacements for existing meters.

ii. Replacement of an existing meter was not limited to circumstances where the meter had reached the end of its useful life. Existing work requirements included government required exchanges, meter upgrades or downgrades, alterations and meter reading/access considerations.

iii. Replacement was also not limited to meters that were damaged or otherwise unusable. The need for a meter exchange depended on the underlying work requirement.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, pp. 9-12 and Appendix 3

Preamble:

For 2025, forecast Dawn supply purchase costs were classified between system commodity costs, transportation, and load balancing costs (split between peaking and seasonal). The Empress reference price, inclusive of fuel, is applied to forecast Dawn and peaking supply purchase volumes to classify a proportion of these purchase costs as system commodity supply. Any forecast price premium for gas supply purchases at Dawn over the Empress reference price is attributed to the transportation and load balancing (peak and seasonal) classification in the same proportion as the amount included in rates (20% deemed transportation, 71% load balancing - seasonal, and 9% load balancing - peak).

There is no approved methodology for the EGD rate zone to determine a classification split of actual Dawn and peaking supply purchases. Supply purchases variances are recorded as commodity and load balancing variances within the PGVA components.

The variance between the forecast and actual price differential of Empress supply and Dawn supply is applied to actual Dawn supply purchases each month plus the variance between forecast and actual peak costs and load balancing fees is recognized as the load balancing variance in the PGVA. Actual load balancing variance costs for 2025 was a debit to ratepayers of $40.1 million as provided at Appendix 3. Load balancing variance costs are allocated to each customer class in the same manner as the allocation of load balancing costs in rates.

Question(s):

a) Please confirm, or correct, our understanding of Enbridge Gas's load balancing cost allocation methodology for the EGD Rate Zone:
    - On a forecast basis, the premium for gas supply purchases at Dawn relative to the Empress price is classified as transportation (20%) and load balancing (80%) (i.e., 71% seasonal and 9% peak).

- When truing-up variances in the PGVA, the variance in the premium for gas supply purchases at Dawn relative to the Empress price (plus other direct load balancing costs) is classified entirely as load balancing (with no allocation to transportation).

If the above is correct, as part of the response, please explain the reason for what appears to be different allocations applied for forecasted costs and for the true-up to actual costs.

b) If the above understanding is correct, please provide the rate class allocations (in dollars and percentages) for 2025 in the following scenarios:

i. The forecast load balancing and transportation costs in rates (Table 2) using the existing approach

ii. The forecast load balancing and transportation costs in rates (Table 2) using the PGVA true-up approach

iii. The PGVA true-up (Appendix 3) using the existing approach

iv. The PGVA true-up (Appendix 3) using the same approach as is applied to the forecast load balancing costs in rates (i.e., with a portion of the costs being allocated to transportation).

Response:

a) Confirmed, please see the response to part b), sub-part iv) for further clarification on the methodology limitations related to actual dawn and peaking supplies.

b)

i. Please see Attachment 1 for the forecast load balancing and transportation costs in rates by rate class related to Dawn and peaking supplies as shown in Exhibit G, Tab 5, Schedule 1, Table 2.

ii. Please see Attachment 2 for the forecast load balancing and transportation costs in rates by rate class related to Dawn and peaking supplies as shown in Exhibit G, Tab 5, Schedule 1, Table 2 adjusted to allocate based on PGVA approach for load balancing delivered supplies.

iii. Please see Attachment 3 for the rate class allocation of the total PGVA true-up amounts related to load balancing and peaking supplies from Exhibit G, Tab 5, Schedule 1, Appendix 3.

iv. Enbridge Gas is unable to produce this scenario as there is no approved methodology for the EGD rate zone to determine a classification split of actual Dawn and peaking supply purchases. The calculation of actual load balancing

cost variances follows a simplified approach, where supply purchase variances are recorded as commodity and load balancing variances within the PGVA components as shown in scenario iii.

Enbridge Gas Inc.
2025 Load Balancing Costs in Rates- EGD Rate Zone by Rate Class

Line No.	Particulars	Rate Class Allocation									
		Total (1)	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 135	Rate 145	Rate 170	Rate 200
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	January 2025 QRAM - EB-2024-0326 (000's)										
	Dawn Supply Purchases Classification										
1	Transportation (2)	32,355	18,017	13,040	-	586	-	63	31	130	489
2	Load balancing - seasonal (2)	115,013	56,865	52,725	-	2,176	341	-	250	792	1,863
3	Load balancing - peak (2)	14,377	8,036	6,205	-	-	19	-	-	-	117
	Peaking Services Classification										
4	Load balancing - peak (3)	3,242	1,812	1,399	-	-	4	-	-	-	26
5	Total	164,987	84,730	73,368	-	2,762	364	63	282	922	2,495
	Load Balancing Costs in Rates										
6	Total load balancing commodity costs (line 2 + 3 + 4)	132,632	66,713	60,329	-	2,176	364	-	250	792	2,007
7	Other load balancing costs (4)	45,960	22,371	21,569	-	732	202	-	96	281	710
8	Total load balancing costs in rates (5)	178,592	89,084	81,898	-	2,908	566	-	346	1,073	2,717
	January 2025 QRAM - EB-2024-0326 (%)										
	Dawn Supply Purchases Classification										
9	Transportation	100%	55.7%	40.3%	0.0%	1.8%	0.0%	0.2%	0.1%	0.4%	1.5%
10	Load balancing - seasonal	100%	49.4%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
11	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
	Peaking Services Classification										
12	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
13	Total	100%	51.4%	44.5%	0.0%	1.7%	0.2%	0.0%	0.2%	0.6%	1.5%
	Load Balancing Costs in Rates										
14	Total load balancing commodity costs	100%	50.3%	45.5%	0.0%	1.6%	0.3%	0.0%	0.2%	0.6%	1.5%
15	Other load balancing costs	100%	48.7%	46.9%	0.0%	1.6%	0.4%	0.0%	0.2%	0.6%	1.5%
16	Total load balancing costs in rates	100%	49.9%	45.9%	0.0%	1.6%	0.3%	0.0%	0.2%	0.6%	1.5%

Notes:

(1) Totals per Exhibit G, Tab 5, Schedule 1, Table 2.

(2) Total Classification calculated as Exhibit G, Tab 5, Schedule 1, Table 2, line 9 minus Exhibit G, Tab 5, Schedule 1, Table 2, line 5 multiplied by 20% for transportation, 71% for load balancing - seasonal, and 9% for load balancing - peak.

(3) The forecast cost of peaking services includes commodity cost

(4) Other load balancing costs indirectly related to the commodity supply purchases such as transportation demand costs and gas in storage carrying costs.

(5) Total load balancing costs taken from QRAM evidence at Exhibit C, Tab 4, Schedule 4, p. 2. See sub-titles for the docket numbers of each QRAM application.

Enbridge Gas Inc.
2025 Load Balancing Costs in Rates- EGD Rate Zone by Rate Class

Line No.	Particulars	Rate Class Allocation									
		Total (1)	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 135	Rate 145	Rate 170	Rate 200
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	April 2025 QRAM - EB-2025-0078 (000's)										
	Dawn Supply Purchases Classification										
1	Transportation (2)	53,316	29,689	21,487	-	965	-	104	52	214	806
2	Load balancing - seasonal (2)	189,521	93,704	86,882	-	3,586	561	-	412	1,305	3,071
3	Load balancing - peak (2)	23,690	13,241	10,224	-	-	32	-	-	-	192
	Peaking Services Classification										
4	Load balancing - peak (3)	3,183	1,779	1,374	-	-	4	-	-	-	26
5	Total	269,710	138,414	119,967	-	4,551	598	104	464	1,519	4,094
	Load Balancing Costs in Rates										
6	Total load balancing commodity costs (line 2 + 3 + 4)	216,395	108,725	98,480	-	3,586	598	-	412	1,305	3,289
7	Other load balancing costs (4)	44,578	21,677	20,939	-	709	198	-	93	272	689
8	Total load balancing costs in rates (5)	260,972	130,402	119,419	-	4,295	795	-	505	1,578	3,978
	April 2025 QRAM - EB-2025-0078 (%)										
	Dawn Supply Purchases Classification										
9	Transportation	100%	55.7%	40.3%	0.0%	1.8%	0.0%	0.2%	0.1%	0.4%	1.5%
10	Load balancing - seasonal	100%	49.4%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
11	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
	Peaking Services Classification										
12	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
13	Total	100%	51.3%	44.5%	0.0%	1.7%	0.2%	0.0%	0.2%	0.6%	1.5%
	Load Balancing Costs in Rates										
14	Total load balancing commodity costs	100%	50.2%	45.5%	0.0%	1.7%	0.3%	0.0%	0.2%	0.6%	1.5%
15	Other load balancing costs	100%	48.6%	47.0%	0.0%	1.6%	0.4%	0.0%	0.2%	0.6%	1.5%
16	Total load balancing costs in rates	100%	50.0%	45.8%	0.0%	1.6%	0.3%	0.0%	0.2%	0.6%	1.5%

Notes:

(1) Totals per Exhibit G, Tab 5, Schedule 1, Table 2.

(2) Total Classification calculated as Exhibit G, Tab 5, Schedule 1, Table 2, line 9 minus Exhibit G, Tab 5, Schedule 1, Table 2, line 5 multiplied by 20% for transportation, 71% for load

(3) The forecast cost of peaking services includes commodity costs plus

(4) Other load balancing costs indirectly related to the commodity supply purchases such as transportation demand costs and gas in storage carrying costs.

(5) Total load balancing costs taken from QRAM evidence at Exhibit C, Tab 4, Schedule 4, p. 2. See sub-titles for the docket numbers of each QRAM application.

Enbridge Gas Inc.
2025 Load Balancing Costs in Rates- EGD Rate Zone by Rate Class

Line No.	Particulars	Rate Class Allocation									
		Total (1)	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 135	Rate 145	Rate 170	Rate 200
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	July 2025 QRAM - EB-2025-0165 (000's)										
	Dawn Supply Purchases Classification										
1	Transportation (2)	36,304	20,216	14,631	-	657	-	71	35	145	549
2	Load balancing - seasonal (2)	129,051	63,806	59,161	-	2,442	382	-	281	889	2,091
3	Load balancing - peak (2)	16,131	9,017	6,962	-	-	22	-	-	-	131
	Peaking Services Classification										
4	Load balancing - peak (3)	2,921	1,633	1,261	-	-	4	-	-	-	24
5	Total	184,408	94,672	82,015	-	3,099	408	71	316	1,034	2,794
	Load Balancing Costs in Rates										
6	Total load balancing commodity costs (line 2 + 3 + 4)	148,104	74,456	67,384	-	2,442	408	-	281	889	2,246
7	Other load balancing costs (4)	45,657	22,219	21,431	-	727	201	-	95	279	706
8	Total load balancing costs in rates (5)	193,761	96,674	88,814	-	3,169	609	-	376	1,168	2,951
	July 2025 QRAM - EB-2025-0165 (%)										
	Dawn Supply Purchases Classification										
9	Transportation	100%	55.7%	40.3%	0.0%	1.8%	0.0%	0.2%	0.1%	0.4%	1.5%
10	Load balancing - seasonal	100%	49.4%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
11	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
	Peaking Services Classification										
12	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
13	Total	100%	51.3%	44.5%	0.0%	1.7%	0.2%	0.0%	0.2%	0.6%	1.5%
	Load Balancing Costs in Rates										
14	Total load balancing commodity costs	100%	50.3%	45.5%	0.0%	1.6%	0.3%	0.0%	0.2%	0.6%	1.5%
15	Other load balancing costs	100%	48.7%	46.9%	0.0%	1.6%	0.4%	0.0%	0.2%	0.6%	1.5%
16	Total load balancing costs in rates	100%	49.9%	45.8%	0.0%	1.6%	0.3%	0.0%	0.2%	0.6%	1.5%

Notes:

(1) Totals per Exhibit G, Tab 5, Schedule 1, Table 2.

(2) Total Classification calculated as Exhibit G, Tab 5, Schedule 1, Table 2, line 9 minus Exhibit G, Tab 5, Schedule 1, Table 2, line 5 multiplied by 20% for transportation, 71% for

(3) The forecast cost of peaking services includes commodity costs plus c

(4) Other load balancing costs indirectly related to the commodity supply purchases such as transportation demand costs and gas in storage carrying costs.

(5) Total load balancing costs taken from QRAM evidence at Exhibit C, Tab 4, Schedule 4, p. 2. See sub-titles for the docket numbers of each QRAM application.

Enbridge Gas Inc.
2025 Load Balancing Costs in Rates- EGD Rate Zone by Rate Class

Line No.	Particulars	Rate Class Allocation									
		Total (1)	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 135	Rate 145	Rate 170	Rate 200
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	October 2025 QRAM - EB-2025-0244 (000's)										
	Dawn Supply Purchases Classification										
1	Transportation (2)	31,025	17,276	12,503	-	562	-	60	30	124	469
2	Load balancing - seasonal (2)	110,283	54,527	50,557	-	2,087	327	-	240	760	1,787
3	Load balancing - peak (2)	13,785	7,705	5,950	-	-	19	-	-	-	112
	Peaking Services Classification										
4	Load balancing - peak (3)	2,973	1,662	1,283	-	-	4	-	-	-	24
5	Total	158,066	81,170	70,293	-	2,648	349	60	270	884	2,392
	Load Balancing Costs in Rates										
6	Total load balancing commodity costs (line 2 + 3 + 4)	127,042	63,894	57,790	-	2,087	349	-	240	760	1,923
7	Other load balancing costs (4)	45,945	22,363	21,562	-	732	202	-	96	281	710
8	Total load balancing costs in rates (5)	172,987	86,257	79,351	-	2,819	551	-	336	1,040	2,633
	October 2025 QRAM - EB-2025-0244 (%)										
	Dawn Supply Purchases Classification										
9	Transportation	100%	55.7%	40.3%	0.0%	1.8%	0.0%	0.2%	0.1%	0.4%	1.5%
10	Load balancing - seasonal	100%	49.4%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
11	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
	Peaking Services Classification										
12	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
13	Total	100%	51.4%	44.5%	0.0%	1.7%	0.2%	0.0%	0.2%	0.6%	1.5%
	Load Balancing Costs in Rates										
14	Total load balancing commodity costs	100%	50.3%	45.5%	0.0%	1.6%	0.3%	0.0%	0.2%	0.6%	1.5%
15	Other load balancing costs	100%	48.7%	46.9%	0.0%	1.6%	0.4%	0.0%	0.2%	0.6%	1.5%
16	Total load balancing costs in rates	100%	49.9%	45.9%	0.0%	1.6%	0.3%	0.0%	0.2%	0.6%	1.5%

Notes:

(1) Totals per Exhibit G, Tab 5, Schedule 1, Table 2.

(2) Total Classification calculated as Exhibit G, Tab 5, Schedule 1, Table 2, line 9 minus Exhibit G, Tab 5, Schedule 1, Table 2, line 5 multiplied by 20% for transportation, 71% for load

(3) The forecast cost of peaking services includes commodity costs plus demand costs.

(4) Other load balancing costs indirectly related to the commodity supply purchases such as transportation demand costs and gas in storage carrying costs.

(5) Total load balancing costs taken from QRAM evidence at Exhibit C, Tab 4, Schedule 4, p. 2. See sub-titles for the docket numbers of each QRAM application.

Enbridge Gas Inc.
2025 Load Balancing Costs in Rates- EGD Rate Zone by Rate Class - PGVA Approach

Line No.	Particulars	Rate Class Allocation									
		Total (1)	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 135	Rate 145	Rate 170	Rate 200
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	January 2025 QRAM - EB-2024-0326 (000's)										
	Dawn Supply Purchases Classification										
1	Transportation (2)	-	-	-	-	-	-	-	-	-	-
2	Load balancing - seasonal (2)	161,744	79,970	74,148	-	3,060	479	-	352	1,114	2,621
3	Load balancing - peak (2)	-	-	-	-	-	-	-	-	-	-
	Peaking Services Classification										
4	Load balancing - peak (3)	3,242	1,812	1,399	-	-	4	-	-	-	26
5	Total	164,987	81,783	75,547	-	3,060	483	-	352	1,114	2,647
	Load Balancing Costs in Rates										
6	Total load balancing commodity costs (line 2 + 3 + 4)	164,987	81,783	75,547	-	3,060	483	-	352	1,114	2,647
7	Other load balancing costs (4)	45,960	22,371	21,569	-	732	202	-	96	281	710
8	Total load balancing costs in rates (5)	210,947	104,153	97,116	-	3,793	685	-	448	1,395	3,357
	January 2025 QRAM - EB-2024-0326 (%)										
	Dawn Supply Purchases Classification										
9	Transportation	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10	Load balancing - seasonal	100%	49.4%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
11	Load balancing - peak	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Peaking Services Classification										
12	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
13	Total	100%	49.6%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
	Load Balancing Costs in Rates										
14	Total load balancing commodity costs	100%	49.6%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
15	Other load balancing costs	100%	48.7%	46.9%	0.0%	1.6%	0.4%	0.0%	0.2%	0.6%	1.5%
16	Total load balancing costs in rates	100%	49.4%	46.0%	0.0%	1.8%	0.3%	0.0%	0.2%	0.7%	1.6%

Notes:

(1) Totals per Exhibit G, Tab 4, Schedule 1, Table 2.

(2) Total Classification calculated as Exhibit G, Tab 5, Schedule 1, Table 2, line 9 minus Exhibit G, Tab 5, Schedule 1, Table 2, line 5 classified as delivered/seasonal supplies under PGVA approach

(3) The forecast cost of peaking services includes commodity costs plus demand costs.

(4) Other load balancing costs indirectly related to the commodity supply purchases such as transportation demand costs and gas in storage carrying costs.

(5) Total load balancing costs taken from QRAM evidence at Exhibit C, Tab 4, Schedule 4, p. 2. See sub-titles for the docket numbers of each QRAM application.

Enbridge Gas Inc.
2025 Load Balancing Costs in Rates- EGD Rate Zone by Rate Class - PGVA Approach

Line No.	Particulars	Rate Class Allocation									
		Total (1)	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 135	Rate 145	Rate 170	Rate 200
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	April 2025 QRAM - EB-2025-0078 (000's)										
	Dawn Supply Purchases Classification										
1	Transportation (2)		-	-	-	-	-	-	-	-	-
2	Load balancing - seasonal (2)	266,527	131,778	122,183	-	5,043	789	-	580	1,836	4,318
3	Load balancing - peak (2)		-	-	-	-	-	-	-	-	-
	Peaking Services Classification										
4	Load balancing - peak (3)	3,183	1,779	1,374	-	-	4	-	-	-	26
5	Total	269,710	133,557	123,557	-	5,043	794	-	580	1,836	4,344
	Load Balancing Costs in Rates										
6	Total load balancing commodity costs (line 2 + 3 + 4)	269,710	133,557	123,557	-	5,043	794	-	580	1,836	4,344
7	Other load balancing costs (4)	44,578	21,677	20,939	-	709	198	-	93	272	689
8	Total load balancing costs in rates (5)	314,288	155,234	144,496	-	5,752	992	-	673	2,108	5,033
	April 2025 QRAM - EB-2025-0078 (%)										
	Dawn Supply Purchases Classification										
9	Transportation	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10	Load balancing - seasonal	100%	49.4%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
11	Load balancing - peak	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Peaking Services Classification										
12	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
13	Total	100%	49.5%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
	Load Balancing Costs in Rates										
14	Total load balancing commodity costs	100%	49.5%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
15	Other load balancing costs	100%	48.6%	47.0%	0.0%	1.6%	0.4%	0.0%	0.2%	0.6%	1.5%
16	Total load balancing costs in rates	100%	49.4%	46.0%	0.0%	1.8%	0.3%	0.0%	0.2%	0.7%	1.6%

Notes:

(1) Totals per Exhibit G, Tab 4, Schedule 1, Table 2.

(2) Total Classification calculated as Exhibit G, Tab 5, Schedule 1, Table 2, line 9 minus Exhibit G, Tab 5, Schedule 1, Table 2, line 5 classified as delivered/seasonal supplies under PGVA approach

(3) The forecast cost of peaking services includes commodity costs plus demand costs.

(4) Other load balancing costs indirectly related to the commodity supply purchases such as transportation demand costs and gas in storage carrying costs.

(5) Total load balancing costs taken from QRAM evidence at Exhibit C, Tab 4, Schedule 4, p. 2. See sub-titles for the docket numbers of each QRAM application.

Enbridge Gas Inc.
2025 Load Balancing Costs in Rates- EGD Rate Zone by Rate Class - PGVA Approach

Line No.	Particulars	Rate Class Allocation									
		Total (1)	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 135	Rate 145	Rate 170	Rate 200
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	July 2025 QRAM - EB-2025-0165 (000's)										
	Dawn Supply Purchases Classification										
1	Transportation (2)	-	-	-	-	-	-	-	-	-	-
2	Load balancing - seasonal (2)	181,487	89,732	83,199	-	3,434	538	-	395	1,250	2,940
3	Load balancing - peak (2)	-	-	-	-	-	-	-	-	-	-
	Peaking Services Classification										
4	Load balancing - peak (3)	2,921	1,633	1,261	-	-	4	-	-	-	24
5	Total	184,408	91,365	84,459	-	3,434	541	-	395	1,250	2,964
	Load Balancing Costs in Rates										
6	Total load balancing commodity costs (line 2 + 3 + 4)	184,408	91,365	84,459	-	3,434	541	-	395	1,250	2,964
7	Other load balancing costs (4)	45,657	22,219	21,431	-	727	201	-	95	279	706
8	Total load balancing costs in rates (5)	230,066	113,583	105,890	-	4,161	742	-	490	1,529	3,670
	July 2025 QRAM - EB-2025-0165 (%)										
	Dawn Supply Purchases Classification										
9	Transportation	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10	Load balancing - seasonal	100%	49.4%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
11	Load balancing - peak	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Peaking Services Classification										
12	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
13	Total	100%	49.5%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
	Load Balancing Costs in Rates										
14	Total load balancing commodity costs	100%	49.5%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
15	Other load balancing costs	100%	48.7%	46.9%	0.0%	1.6%	0.4%	0.0%	0.2%	0.6%	1.5%
16	Total load balancing costs in rates	100%	49.4%	46.0%	0.0%	1.8%	0.3%	0.0%	0.2%	0.7%	1.6%

Notes:

(1) Totals per Exhibit G, Tab 4, Schedule 1, Table 2.

(2) Total Classification calculated as Exhibit G, Tab 5, Schedule 1, Table 2, line 9 minus Exhibit G, Tab 5, Schedule 1, Table 2, line 5 classified as delivered/seasonal supplies under PGVA approach

(3) The forecast cost of peaking services includes commodity costs plus demand costs.

(4) Other load balancing costs indirectly related to the commodity supply purchases such as transportation demand costs and gas in storage carrying costs.

(5) Total load balancing costs taken from QRAM evidence at Exhibit C, Tab 4, Schedule 4, p. 2. See sub-titles for the docket numbers of each QRAM application.

Enbridge Gas Inc.

2025 Load Balancing Costs in Rates- EGD Rate Zone by Rate Class - PGVA Approach

Line No.	Particulars	Rate Class Allocation									
		Total (1)	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 135	Rate 145	Rate 170	Rate 200
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	October 2025 QRAM - EB-2025-0244 (000's)										
	Dawn Supply Purchases Classification										
1	Transportation (2)	-	-	-	-	-	-	-	-	-	-
2	Load balancing - seasonal (2)	155,093	76,682	71,099	-	2,934	459	-	337	1,068	2,513
3	Load balancing - peak (2)	-	-	-	-	-	-	-	-	-	-
	Peaking Services Classification										
4	Load balancing - peak (3)	2,973	1,662	1,283	-	-	4	-	-	-	24
5	Total	158,066	78,344	72,382	-	2,934	463	-	337	1,068	2,537
	Load Balancing Costs in Rates										
6	Total load balancing commodity costs (line 2 + 3 + 4)	158,066	78,344	72,382	-	2,934	463	-	337	1,068	2,537
7	Other load balancing costs (4)	45,945	22,363	21,562	-	732	202	-	96	281	710
8	Total load balancing costs in rates (5)	204,012	100,707	93,944	-	3,666	665	-	433	1,349	3,247
	October 2025 QRAM - EB-2025-0244 (%)										
	Dawn Supply Purchases Classification										
9	Transportation	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10	Load balancing - seasonal	100%	49.4%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
11	Load balancing - peak	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Peaking Services Classification										
12	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
13	Total	100%	49.6%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
	Load Balancing Costs in Rates										
14	Total load balancing commodity costs	100%	49.6%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
15	Other load balancing costs	100%	48.7%	46.9%	0.0%	1.6%	0.4%	0.0%	0.2%	0.6%	1.5%
16	Total load balancing costs in rates	100%	49.4%	46.0%	0.0%	1.8%	0.3%	0.0%	0.2%	0.7%	1.6%

Notes:

(1) Totals per Exhibit G, Tab 4, Schedule 1, Table 2.

(2) Total Classification calculated as Exhibit G, Tab 5, Schedule 1, Table 2, line 9 minus Exhibit G, Tab 5, Schedule 1, Table 2, line 5 classified as delivered/seasonal supplies under PGVA approach

(3) The forecast cost of peaking services includes commodity costs plus demand costs.

(4) Other load balancing costs indirectly related to the commodity supply purchases such as transportation demand costs and gas in storage carrying costs.

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Enbridge Gas Inc.
2025 Load Balancing Costs Variances and Allocation to Rate Classes

Line No.	Particulars	Rate Class Allocation									
		Total (1)	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 135	Rate 145	Rate 170	Rate 200
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Load Balancing Price Variance Classification										
1	Transportation (2)	-	-	-	-	-	-	-	-	-	-
2	Load balancing - seasonal (2)	41,285.3	20,412.5	18,926.3	-	781.1	122.3	-	89.8	284.4	668.9
3	Load balancing - peak (2)	-	-	-	-	-	-	-	-	-	-
	Peaking Cost Variance Classification										
4	Load balancing - peak (3)	(1,141.8)	(638.2)	(492.8)	-	-	(1.5)	-	-	-	(9.3)
5	Total	40,143.5	19,774.3	18,433.5	-	781.1	120.7	-	89.8	284.4	659.6
	Load Balancing Price Variance Classification										
6	Transportation	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	Load balancing - seasonal	100%	49.4%	45.8%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%
8	Load balancing - peak	0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Peaking Cost Variance Classification										
9	Load balancing - peak	100%	55.9%	43.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.8%
10	Total	100%	49.3%	45.9%	0.0%	1.9%	0.3%	0.0%	0.2%	0.7%	1.6%

Notes:

(1) Totals per Exhibit G, Tab 5, Schedule 1, Appendix 3, column (l) and (o).

(2) Total classification as delivered supplies under PGVA approach. Delivered Supplies portion of PGVA load balancing amounts are allocated using the Storage Space factor.

(3) Variance in cost of peaking services includes commodity costs plus demand costs. Peaking supplies portion of PGVA load balanicng amounts are allocated using deliverability factor.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, Page 2, Table 1 *Historical UFG Volumes for EGI Regulated*; Exhibit G, Tab 1, Schedule 3, Page 9, *Figure 2: Number of Estimate Bills per Month and Figure 3: Percentage of Estimated Bills vs Total Customers*

Preamble:

"Figure 1 shows historical UFG volumes for Enbridge Gas from 2013 to 2025 and includes the 2024 OEB-approved UFG volume forecast."

Question(s):

a) Please explain why the text quoted in the Preamble mentions Figure 1 but appears to refer to Table 1.

b) If the 2024 UFG volume of 334,888 10 3 m3 is the 2024 OEB-approved UFG volume forecast what was the actual UFG for 2024?

c) The UFG volumes increased from 2023 to 2025 as did the number of estimated bills. Does the number of estimated bills have any impact on UFG? Please explain your answer.

d) What has Enbridge Gas done to reduce the volume of UFG in 2025? Please list all activities and explain why they were unsuccessful.

e) What incentives are in place for Enbridge Gas to reduce UFG volumes?

Response:

a) The historical unaccounted for gas (UFG) volumes and the 2024 OEB-approved UFG volume forecast referenced in the Preamble are presented in Figure 1, which corresponds to the line chart provided in Exhibit C, Tab 2, Schedule 3, page 3.

b) Table 1 provides the actual UFG volumes from 2013 to 2025. The 2024 UFG of 334,888 103m3 represents the actual UFG volume for 2024, not the 2024 OEB-approved UFG volume. The 2024 OEB-approved volume is 243,682 103m3, which

is shown as the red line in the chart provide in Figure 1, as well as Exhibit C, Tab 2, Schedule 3 Attachment 1, page 1, Line 1.

c) Estimated consumption is trued-up once an actual meter read is obtained, ensuring that customer consumption is billed correctly and that there is no long-term UFG created because of billing estimation.

d) Please see response at Exhibit I.STAFF-1.

e) Given the current OEB-approved UFG framework, which includes a sharing mechanism, Enbridge Gas is incentivized to maintain UFG volumes below the approved volume of 243,682 103m3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, Page 4

Preamble:

"Enbridge Gas's total system (utility and non-utility) UFG in 2025 amounted to approximately 435,240 103m3 compared to total system throughput for that same year of approximately 56,875,530 103m3 (0.77%)."

Question(s):

a) Please explain how UFG was allocated between utility and non-utility volumes.

b) Was the percentage of UFG volume the same for utility and non-utility volumes? Please explain your answer.

Response:

a) The allocation between utility and non-utility volumes associated with UFG is determined on a monthly basis using a volumetric allocator. The non-utility allocator is calculated as the ratio of actual gross[1] unregulated storage activity to total actual gross storage and transportation activity for the month. The non-utility portion of UFG volumes is derived by applying this allocator to total system UFG volumes. The utility portion is the difference between total system UFG volumes and the volumes allocated to non-utility activities. This methodology for allocating UFG costs between regulated and unregulated operations was approved as part of the 2024 Rebasing Phase 2 proceeding[2].

b) The percentage of UFG volume of 0.77% referenced in Exhibit C, Tab 2, Schedule 3 page 4 is calculated based on total UFG volumes (utility and non utility) compared to total system throughput volumes. This calculation uses total sendout volumes to

[1] Gross activity = injections plus withdrawals (ie. 100 GJ injections and 100 GJ of withdrawals = 200 GJ of gross activity).
[2] EB-2024-0111, Decision on Settlement Proposal, Exhibit N, Tab 1, Schedule 1, p.25.

represent throughput, which is the combination of billed consumption volumes for utility customers plus transportation volumes. There is no comparable calculation for the percentage of throughput calculated discretely for utility and non-utility volumes.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit G, Tab 1, Schedule 3, Page 7 *Step 5: Automated or Manual Review (Implausible Reads)*

Preamble:

“A meter reading may be identified as "implausible" when it differs significantly from the level of consumption expected for a particular customer during a billing period.

…As a result, a bill may be identified as estimated even though a meter reading was received. This occurs because the reading could not be validated at the time of billing and additional review was necessary to protect the customer from potential billing inaccuracies.”

Question(s):

a) What is the percent difference between actual reading and expected consumption used to identify a meter reading as implausible?
b) Why does Enbridge Gas assume that the expected consumption is plausible, and the actual meter reading is implausible?
c) Is Enbridge Gas aware that some customers are replacing their old gas furnaces with heat pumps and that could make the estimated consumption based on the old gas furnace implausible?
d) How many months are there between billing and additional review?
e) How are customers protected from estimated bill inaccuracies?

Response:

a) The percentage variance between an actual meter reading and expected consumption used to identify a meter reading as an implausible reading is not a fixed value. SAP CIS establishes customer-specific thresholds based on historical consumption and account characteristics. In some scenarios, the control may be

triggered as low as 30%. The implausible-reading functionality is a SOX control that is subject to regular audits.

b) Enbridge Gas does not assume that expected consumption is correct and an actual meter reading is incorrect. Rather, where a submitted meter reading falls outside the customer-specific range of expected consumption, the reading is identified for additional validation before it is used for billing. This process is intended to protect customers from potentially inaccurate bills resulting from data-entry errors, meter reading errors, unusual consumption patterns, or other circumstances requiring further review. Once the review is completed and a valid meter reading is confirmed, the account is reconciled as necessary to reflect the actual consumption.

c) Yes, Enbridge Gas recognizes that customer consumption patterns may change because of factors such as replacing older gas furnaces with heat pumps, changes in occupancy, weather conditions or changes in customer behaviour. Estimation uses multiple customer-specific inputs, including historical consumption, weather conditions during the billing period and prior validated meter readings. As a result, a significant change in consumption may not be fully reflected immediately in an estimate. Any difference between estimated and actual consumption is subsequently reconciled when a valid actual meter reading is obtained.

d) The timing of additional review depends on the circumstances of the individual account and the availability of a valid meter reading. An account may be reviewed when a subsequent meter reading is obtained or when additional meter readings become available such as a customer submitted reading. Any required adjustment is reflected through the account reconciliation process once a valid actual meter reading has been confirmed.

e) Enbridge Gas provides customers with several safeguards to mitigate the potential impact of inaccuracies arising from estimated bills:

   i. Customers may submit meter readings manually through multiple channels, including the interactive voice response system, a live agent, My Account, and the mobile application.
   ii. Submitted meter readings are subject to validation controls designed to identify readings that appear inconsistent with expected consumption before they are used for billing, helping protect customers from potentially inaccurate bills.
   iii. Estimated bills are interim in nature and customer accounts are reconciled when a valid actual meter reading is obtained, ensuring that customers are ultimately billed based on actual consumption.
   iv. Where a billing adjustment results in customer concerns regarding payment amounts, Enbridge Gas will review estimation parameters with the customer and offers customers flexible payment arrangements.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit G, Tab 1, Schedule 3, Page 8, *Section 3.4 Estimated Billing Volumes and Trend*

Preamble:

“Because Enbridge Gas uses a bi-monthly meter reading model, estimated billing is an expected and recurring component of normal operations.”

Question(s):

For a customer who has replaced an old gas furnace with a hybrid heat pump system and uses less gas does that mean that every second month the bill is based on consumption of the old gas furnace even if the customer provides the actual meter reading to Enbridge?

Response:

No. If a customer submits an actual meter reading to Enbridge Gas and the reading is accepted for billing purposes, the customer will be billed based on that actual meter reading.

The SAP CIS estimation process uses available historical consumption information available for the customer account when generating an estimated bill. As actual meter readings are obtained and recorded, changes in customer consumption patterns become reflected in the historical information available to the estimation process. Customers may also contact Enbridge Gas to advise of changes that may affect their consumption patterns.

Estimated billing is an interim billing mechanism used when an actual meter reading is unavailable. Once an actual meter reading is obtained, the customer's account is reconciled to reflect actual consumption.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit G, Tab 1, Schedule 3, Page 9, Figure 2: Number of Estimate Bills per Month and Figure 3: Percentage of Estimated Bills vs Total Customers

Question(s):

a) Figure 2 indicates that the number of estimated bills per month has increased from 2023 to 2025. Please explain why.

b) Figure 3 indicates that the percentage of estimated bills vs total customers has increased from 2023 to 2025. Please explain why.

c) Please expand Figures 2 and 3 to show 2020 and 2021.

d) Should the OEB be concerned about the increased trend in estimated bills? If the answer is no, please explain why not.

Response:

a) Figure 2 indicates that the number of estimated bills increased in certain months between 2023 to 2025. A key factor contributing to estimated bills is the inability to obtain an actual meter reading. As discussed in Exhibit G, Tab 1, Schedule 3, Section 4.4, Enbridge Gas continues to experience increasing challenges accessing customer meters. For example, during the winter of 2025, significant snowfall, snow accumulation and severe winter weather conditions further limited access to customers meters, resulting in additional challenges for meter reading activities and contributing to higher estimated bills. SAP CIS data indicates that February and December 2025 experienced more severe winter conditions than the corresponding months in 2023, an increase in colder temperatures of 12% and 39%, respectively, which further contributed to meter reading challenges during those periods.

b) As shown in Figure 3, the percentage of estimated bills relative to the total number of customers increased from 2023 to 2025 for the reasons described in response (a) above. While the total customer base also increased during this period, the number of estimated bills increased at a greater rate due to continued meter access challenges and seasonal factors affecting meter reading activities. For additional

discussion regarding meter access challenges, please refer to Exhibit Gm Schedule 1, Schedule 3, Section 4.4.

c) Enbridge Gas does not have comparable data for 2020 and 2021 in a reportable format. The information used to prepare Figures 2 and 3 is not available for those years through the existing reporting capabilities.

d) The increase in the number of estimated bills attributable to meter access challenges remains an area of focus for Enbridge Gas. However, the OEB should not be concerned about the observed trend in estimated bills. Estimated bills are an interim measure used when an actual meter reading is unavailable and are a standard component of utility billing operations. Customers are ultimately billed based on actual consumption once an actual meter reading is obtained and the account is reconciled. As noted in Exhibit G, Tab 1, Schedule 3, estimated billing supports the timely issuance of bills while ensuring actual consumption is reflected once an actual meter reading becomes available. Further, customer complaints related to estimated billing remain low and have decreased since 2023 as reflected in Exhibit G, Tab 1, Schedule 3, Table 4 in proportion of overall customer estimated bills.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit G, Tab 1, Schedule 3, Page 10, Section 3.5.1 Enhanced Review of Implausible Meter Readings

Preamble:

"As part of its ongoing continuous improvement efforts, Enbridge Gas has identified opportunities to further strengthen the review and validation of implausible meter readings before billing adjustments are applied.
Enhancements under review or development include additional safeguards that evaluate:

- historical customer consumption patterns;
- previous actual meter readings;
- seasonal usage trends;
- account characteristics; and
- other relevant customer information "

Question(s):

a) Why is Enbridge only concerned about implausible meter readings but not about implausible estimated consumption of gas?
b) How many years of historical customer consumption patterns are currently used in the estimation process?
c) Are all years of historical consumption given the same weighing or are more recent consumption patterns given higher weighing?
d) Are only actual readings used for historical consumption patterns?
e) Considering that many residential customers are switching to hybrid heat pump systems which reduce gas consumption, how is that used in the historical consumption pattern data?

Response:

a) Enbridge Gas is concerned with both implausible meter readings and the accuracy of estimated consumption. The enhancements described in Section 3.5.1 relate specifically to the review and validation of actual meter readings that have been identified as implausible prior to being used for billing purposes. Estimated consumption is also subject to validation through the SAP CIS estimation process, which uses available account and consumption information to generate a reasonable estimate when an actual meter reading is unavailable.

   Estimated billing is a standard and necessary component of natural gas utility operations. It is used throughout the utility industry to support the timely issuance of customer bills when an actual meter reading is unavailable or impractical to obtain. Estimated bills are an interim billing mechanism and once an actual meter read is obtained, the account is reconciled to reflect the customer's actual consumption.

   The enhancements described in Section 3.5.1 are intended to strengthen the review of the implausible actual meter readings before a billing adjustment is applied.

b) The estimation process uses historical consumption information maintained within SAP CIS that is available for the customer account. The amount of historical information available varies by customers and depends on factors such as the age of the account and the availability of system records.

c) Historical consumption data used in the estimation process is not weighted based on the age of the consumption data.

d) Yes. Historical consumption patterns used within the estimation process are based on actual meter readings. Actual meter readings may be obtained by meter readers, submitted by customers, or recorded on work orders from field work.

e) The SAP CIS estimation process relies on historical consumption information available for the customer account. As actual meter readings are obtained and recorded, changes in customer consumption patterns become reflected in the historical information available to the estimation process. Customers may also contact Enbridge Gas to advise of changes that may affect their consumption patterns.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe Research Foundation (EP)

Interrogatory

Reference:

Exhibit G, Tab 1, Schedule 3, *Section 3.5.2 Reduced Automated Re-Estimation Pages 10 and 11*

Preamble:

"Enhancements are being implemented to reduce circumstances where actual meter readings may be subsequently replaced through automated estimation processes.

Under the revised approach, the system will only automatically re-estimate one actual meter reading within a six-month period, providing additional protection against unnecessary replacement of actual consumption information.

For example, if an actual meter reading appears inconsistent with historical consumption patterns, the SAP CIS system may automatically replace the actual meter reading with an estimated reading. Any subsequent actual meter reading for the same account that requires further review within the next six months will be reviewed manually rather than automatically replaced with another estimate. This increases the number of actual meter readings retained in the billing record and reduces the use of estimated consumption data."

Question(s):

a) For a customer who has replaced an old gas furnace with a hybrid heat pump system and uses less gas, why would re-estimating one actual meter reading provide additional protection against unnecessary replacement of actual consumption information if the re-estimated meter reading is based on consumption of the old gas furnace?
b) How many actual meter readings were reviewed manually in 2025?
c) Of the actual meter readings that were reviewed how many were found to indicate lower consumption of gas than the estimated consumption based on historical data?
d) In cases where a customer has been overcharged for several months based on estimated consumption of gas and Enbridge credits the customer's account, does

that credit include interest? If the answer is yes, what interest rate is applied? If the answer is no, why not?

e) Is the manual review performed by employees of Enbridge Gas or is it performed by individuals working for a contractor?

f) If the manual review is performed by the contractor, how does Enbridge Gas ensure that it is done correctly?

Response:

a) The additional protection is provided by limiting automated re-estimation and requiring subsequent exceptions to be reviewed manually. For a customer whose consumption may have changed, including following the installation of a hybrid heat pump system, manual review provides an opportunity to validate the actual meter reading and assess whether the consumption reflected in the reading is consistent with the customer's circumstances rather than relying solely on historical consumption patterns.

b) In 2025, 245,821 actual reads were reviewed manually.

c) Enbridge Gas does not maintain this information in a reportable format. Determining the number of manually reviewed actual meter readings that were validated as lower than consumption estimated based on historical data would require a review of individual account records and is not available through existing reporting.

d) No. Interest is not applied when an account is adjusted following the receipt of an actual meter reading. Estimated bills are an interim component of the billing process and the subsequent adjustment represents a reconciliation of estimated consumption to actual consumption. Once a validated actual meter reading becomes available, the account is adjusted to reflect the customer's actual consumption.

e) The manual review of implausible meter readings is performed by trained contractor personnel in accordance with Enbridge Gas procedures. Any escalations are completed by employees of Enbridge Gas.

f) Enbridge Gas maintains documented procedures to support the accurate, reliable, and consistent completion of manual reviews. Billing agents receive comprehensive training on applicable procedures and relevant aspects of the natural gas industry to ensure they have the knowledge required to perform their responsibilities effectively. Enbridge Gas monitors performance through quality assurance reviews and procedures are reviewed and updated as necessary. Escalations and exception scenarios are handled by Enbridge Gas employees.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 5 and
EB-2024-0111 Exhibit N, Tab 1, Schedule 1, Pages 25-26 Item 12

Preamble:

We would like to understand better the implementation of the referenced settlement agreement pertaining to storage.

Question(s):

Please provide the capital continuity reporting related to storage for the utility and non-utility starting with 2023 and including 2024 and 2025.

a) Please show the specific application of approved allocation methodology and the resulting impacts in these reports including 2025 additions.

Response:

Attachments 1 and 2 are the 2024 and 2025 Unregulated Gross Asset Continuity schedules and Attachment 3 is the 2024 Regulated Gross Asset Continuity schedule. The 2025 Regulated Gross Asset Continuity schedule is found at Exhibit B, Tab 1, Schedule 5, page 3 of 5. In addition, a project-level summary of the 2024 and 2025 Underground Storage asset addition allocation between the Regulated and Unregulated businesses has been provided.

a) Overall, as can be seen in the exhibits and attachments, Enbridge Gas has reported approximately $98 million and $51 million in regulated and unregulated storage asset additions between 2024 & 2025. These additions reflect Enbridge Gas' application of the settled and approved storage asset allocation methodology.

   The project-level allocation summary, at Attachment 4, is based on 2024 and 2025 asset additions. This approach differs from the historical UGL rate zone Allocation

Reports provided in the 2024 Rebasing Phase 2[1] application at Exhibit JT3.28, Attachments 2-12, which presented the allocation for 2013-2023 based on each year's ending asset balance.

The allocation percentages presented in the project-level summary may not, in all cases, correspond directly to the approved 62% regulated / 38% unregulated allocation. This does not indicate that a different approved allocation methodology has been applied. Rather, differences may arise from the nature and timing of the asset additions reflected in the report.

For example, additions recorded late in the year as well as trailing costs may be recorded and/or adjusted in a subsequent year for various projects. Where such costs relate to projects that pre-date the current allocation methodology, no allocation may be reflected against those additions.

These timing differences, including adjustments or true-ups recorded against a project, can also result in calculated project-level allocation percentages that exceed 100% or otherwise appear disproportionate when the regulated or unregulated allocation is compared with the net additions recorded in a particular year. Accordingly, the percentages derived from individual project additions should not be interpreted as the allocation rate applied to the project.

[1] EB-2024-0111.

EGI UNREGULATED GAS PLANT
CONTINUITY OF PROPERTY, PLANT AND EQUIPMENT
2024 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2023	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2024
		($Millions)	($Millions)	($Millions)	($Millions)
	Underground Storage Plant - EGI				
1.	Land	9.9	-	-	9.9
2.	Land rights	38.4	0.0	-	38.4
3.	Structures and improvements	29.1	2.6	-	31.7
4.	Wells	226.7	8.4	(1.9)	233.2
5.	Field Lines	43.8	4.1	-	47.9
6.	Compressor equipment	203.1	3.1	(0.1)	206.1
7.	Measuring and regulating equipment	128.2	4.6	(0.1)	132.7
8.	Base pressure gas	35.4	-	-	35.4
9.	ARO on oil assets	13.3	-	-	13.3
10.	Sub-Total	727.9	22.9	(2.1)	748.7
	Transmission Plant - EGI				
11.	Mains	66.8	8.3	-	75.1
12.	Sub-Total	66.8	8.3	-	75.1
	General Plant - EGI				
13.	Land	0.0	0.0	-	0.0
14.	Structures and improvements	6.2	0.1	(0.2)	6.2
15.	Renewable Natural Gas	13.6	15.8	-	29.4
16.	Office furniture	0.7	0.0	(0.0)	0.6
17.	Office equipment	2.1	0.0	(0.0)	2.1
18.	Transportation equipment	4.2	0.2	(0.1)	4.4
19.	NGV	0.2	0.0	-	0.2
20.	Heavy work equipment	1.5	0.1	(0.0)	1.6
21.	Tools and work equipment	2.7	0.0	(0.4)	2.4
22.	Communication structures & equip.	0.3	(0.0)	(0.1)	0.2
23.	Computer equipment	1.2	0.2	(0.1)	1.3
24.	CIS	0.0	0.1	-	0.1
25.	Software	3.3	0.4	(1.4)	2.4
26.	WAMS	1.6	-	-	1.6
27.	Sub-Total	37.7	17.0	(2.2)	52.4
28.	Total	832.4	48.1	(4.3)	876.2

EGI UNREGULATED GAS PLANT
CONTINUITY OF PROPERTY, PLANT AND EQUIPMENT
2025 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2024	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2025
		($Millions)	($Millions)	($Millions)	($Millions)
	Underground Storage Plant - EGI				
1.	Land	9.9	2.9	-	12.8
2.	Land rights	38.4	0.0	-	38.4
3.	Structures and improvements	31.7	2.4	-	34.1
4.	Wells	233.2	9.9	-	243.1
5.	Field Lines	47.9	4.1	-	52.1
6.	Compressor equipment	206.1	3.2	-	209.3
7.	Measuring and regulating equipment	132.7	5.3	-	138.0
8.	Base pressure gas	35.4	-	-	35.4
9.	ARO on oil assets	13.3	-	-	13.3
10.	Sub-Total	748.7	27.8	-	776.5
	Transmission Plant - EGI				
11.	Transmission Mains Steel	75.1	1.0	-	76.0
12.	Sub-Total	75.1	1.0	-	76.0
	General Plant - EGI				
13.	Land	0.0	0.2	-	0.3
14.	Structures and improvements	6.2	0.0	(0.1)	6.1
15.	Renewable Natural Gas	29.4	(0.1)	-	29.3
16.	Office furniture	0.6	0.0	(0.0)	0.6
17.	Office equipment	2.1	(0.0)	(0.0)	2.0
18.	Transportation equipment	4.4	0.5	(0.1)	4.8
19.	NGV	0.2	-	-	0.2
20.	Heavy work equipment	1.6	0.2	(0.0)	1.7
21.	Tools and work equipment	2.4	0.3	(0.0)	2.6
22.	Communication structures & equip.	0.2	0.0	-	0.2
23.	Computer equipment	1.3	0.3	(0.2)	1.4
24.	CIS	0.1	-	-	0.1
25.	Software	2.4	0.4	(0.6)	2.2
26.	WAMS	1.6	-	-	1.6
27.	Sub-Total	52.4	1.7	(1.0)	53.1
28.	Total	876.2	30.5	(1.0)	905.7

EGI Utility Gross Plant
Year End Balances and Average of Monthly Averages
2024 Actual

Line No.	Particulars ($ millions)	Col. 1 Opening Balance Dec.2023	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2024	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2024	Col. 7 Average of Monthly Averages
	Underground Storage Plant - EGI							
1	Land (450)	18.2	0.3	-	18.4	(1.0)	17.4	17.2
2	Land rights (451)	74.8	0.0	-	74.8	-	74.8	74.8
3	Structures and improvements (452)	149.4	4.5	(11.3)	142.5	(0.1)	142.4	142.2
4	Wells (453)	146.7	8.3	(0.2)	154.8	-	154.8	149.7
5	Well equipment (454)	16.6	0.3	-	16.9	-	16.9	16.8
6	Field Lines (455)	210.0	19.3	-	229.3	-	229.3	222.6
7	Compressor equipment (456)	726.1	(5.9)	(46.3)	673.9	(0.5)	673.4	687.0
8	Measuring and regulating equipment (457)	195.1	28.4	(1.0)	222.5	-	222.5	211.4
9	Base pressure gas (458)	75.7	-	-	75.7	-	75.7	75.7
10	Sub-Total	1,612.6	55.0	(58.7)	1,608.8	(1.5)	1,607.3	1,597.5
	Transmission Plant - EGI							
11	Land (460) [1]	85.8	1.9	-	87.7	-	87.7	85.9
12	Land Rights (461.001) [1]	88.4	3.3	-	91.7	-	91.7	88.5
13	Structures & improvements (462/463/464)	186.6	1.1	-	187.8	-	187.8	186.7
14	Mains (465) [1]	2,984.3	321.6	(8.1)	3,297.8	-	3,297.8	3,039.4
15	Compressor equipment (466)	1,037.2	4.1	-	1,041.3	-	1,041.3	1,037.7
16	Measuring and regulating equipment (467) [1]	555.3	34.3	-	589.6	-	589.6	561.9
17	Line Pack Gas	0.2	(0.0)	-	0.2	-	0.2	0.2
18	Sub-Total	4,937.7	366.5	(8.1)	5,296.1	-	5,296.1	5,000.3
	Distribution Plant - EGI							
19	Renewable Natural Gas (461)	9.8	8.8	-	18.6	-	18.6	16.1
20	Land (470)	102.2	1.7	-	103.9	-	103.9	102.8
21	Land rights intangibles (471)	66.8	0.1	-	66.8	-	66.8	66.8
22	Structures and improvements (472)	318.7	40.3	(3.0)	355.9	(0.3)	355.6	324.5
23	Services - metallic (473)	652.6	5.4	(2.4)	655.6	-	655.6	650.6
24	Services - plastic (473)	4,898.7	310.4	(10.5)	5,198.6	-	5,198.6	5,035.6
25	Regulators (474)	522.0	22.0	(59.5)	484.5	-	484.5	508.7
26	House regulators & meter installations (474)	27.5	3.7	-	31.2	-	31.2	28.9
27	Mains - metallic (475)	3,753.8	80.6	(7.5)	3,826.9	(2.2)	3,824.7	3,765.7
28	Mains - plastic (475)	3,848.2	107.6	(4.5)	3,951.3	-	3,951.3	3,891.9
29	Mans - envision (475)	181.3	-	-	181.3	-	181.3	181.3
30	NGV station compressors (476)	10.6	0.5	-	11.1	-	11.1	10.9
31	Measuring and regulating equipment (477)	1,101.4	56.8	(7.3)	1,150.9	(0.5)	1,150.4	1,114.5
32	Meters (478)	1,147.8	118.7	(29.9)	1,236.6	-	1,236.6	1,196.3
33	Sub-Total	16,641.2	756.6	(124.6)	17,273.2	(3.1)	17,270.1	16,894.4
	General Plant - EGI							
34	Investment in leased assets (101)	16.3	0.0	-	16.3	-	16.3	16.3
35	Land (480)	0.5	-	-	0.5	-	0.5	0.5
36	Structure & Improvements (482)	235.8	4.9	(8.4)	232.2	(0.2)	232.0	229.8
37	Office furniture and equipment (483)	30.2	0.5	(1.9)	28.7	-	28.7	29.3
38	Transportation equipment (484)	142.3	12.8	(2.9)	152.2	(0.1)	152.2	145.3
39	NGV conversion kits (484)	3.1	0.1	-	3.1	-	3.1	3.1
40	Heavy work equipment (485)	52.7	3.9	0.3	56.8	-	56.8	54.1
41	Tools and work equipment (486)	81.8	1.9	(20.9)	62.8	-	62.8	70.8
42	Rental equipment (487)	2.7	-	-	2.7	-	2.7	2.7
43	NGV rental compressors (487)	8.2	0.8	-	9.0	-	9.0	8.4
44	NGV cylinders (487)	0.6	-	-	0.6	-	0.6	0.6
45	Communication structures & equip. (488)	5.0	0.0	(3.1)	1.9	-	1.9	3.8
46	Computer equipment (490)	23.6	10.3	(3.2)	30.7	-	30.7	25.1
47	Software Aquired/Developed (491)	100.2	24.6	(7.2)	117.6	-	117.6	109.6
48	WAMS (489)	66.3	-	-	66.3	-	66.3	66.3
49	Sub-Total	769.1	59.7	(47.4)	781.5	(0.3)	781.2	765.7
	Local Storage Plant - EGI							
50	Land (440)	0.0	-	-	0.0	-	0.0	0.0
51	Structures and improvements (442)	6.4	1.0	-	7.4	-	7.4	6.8
52	Gas holders - storage (443)	6.0	1.0	-	7.0	-	7.0	6.3
53	Gas holders - equipment (443)	22.2	6.2	-	28.5	-	28.5	23.5
54	Sub-Total	34.6	8.3	-	42.9	-	42.9	36.7
	Intangible Plant - EGI							
55	Inactive services (102)	1.7	-	-	1.7	-	1.7	1.7
56	Franchises and consents (401)	1.2	-	-	1.2	-	1.2	1.2
57	Other intangible plant (402)	0.5	-	-	0.5	-	0.5	0.5
58	Sub-Total	3.3	-	-	3.3	-	3.3	3.3
59	EGI Total	23,998.5	1,246.1	(238.8)	25,005.8	(4.8)	25,001.0	24,298.0

Note:
(1) Col. 2 Includes $189.5 million of Panhandle Regional Expansion Project (PREP).

ENBRIDGE GAS INC.

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

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Please see filed Exhibit I.FRPO-1_Attachment 4 on the OEB's RDS

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Pages 2-3

Preamble:

We would like to better understand the derivation of the normalized amounts by rate class presented in the above reference.

Question(s):

Please provide the Tables in the referenced pages in Excel format

a) Please describe and show the derivation of the normalized amounts in a working Excel spreadsheet for the General Service rates classes.
   i. Please ensure the derivation includes with determination base normalized amounts used for ratemaking
   ii. the normal and actual HDD's used
   iii. the steps to providing the normalized throughputs shown on page 3 and
   iv. the determination of the revenue adjustments resulting from the normalization process

Response:

a)
   i. The 2024-2025 volumes provided in Exhibit B, Tab 2, Schedule 1, pages 2-3 represent unnormalized and normalized actual results. For ratemaking purposes, forecast average use and throughput volumes are used rather than actual results.

   ii.- iii. Please see Attachment 1, Tables 7 and 8 for the 2024 actual and normal (forecast) HDDs. Also, please see Attachment 1 for the steps involved in producing the 2024 actual throughputs normalized to 2024 Forecast HDDs as shown on Exhibit B, Tab 2, Schedule 1, page 3. The total 2024 normalized

throughputs by Rate Class in Attachment 1, Table 13, column (m) align with Exhibit B, Tab 2, Schedule 1, page 3, column (c).

Please see Attachment 2, Tables 7 and 8 for the 2025 actual and normal (forecast) HDDs. Also, please see Attachment 2 for the steps involved in producing the 2025 actual throughputs normalized to 2025 Forecast HDDs as shown on Exhibit B, Tab 2, Schedule 1, page 3. The total 2025 normalized throughputs by Rate Class in Attachment 2, Table 13, column (m) align with Exhibit B., Tab 2, Schedule 1, page 3, column (f).

iv. Normalized revenue is calculated based on normalized throughput volumes, as provided in part iii), multiplied by OEB approved rates.

Determination of Actual Normalized Volumes / Throughputs

with live worked example (Rate 1, Central) for normalization to 2024 forecast HDDs

Method in one line

Normalized volume (10^3 m^3) = [Actual average use − Weather factor × (Actual HDD − Forecast HDD)] × Actual customers ÷ 1,000

Calculation steps

Step	Calculation	What to do	Workbook source	Output / units
1	Identify the segment	Use the exact Region + Rate Class + Sector and month.	2024 Actuals / 2024 Weather Factors	One unique record
2	Calculate actual average use-monthly	Unnormalized volume × 1,000 ÷ actual customer count.	2024 Actuals: Tables 1, 3 and 5	m^3 per customer
3	Calculate HDD variance-monthly	Actual HDD − Forecast HDD for the segment's weather zone.	2024 HDD: Table 9	HDD
4	Calculate weather adjustment-monthly	Weather factor × HDD variance.	2024 Weather Factors: Table 10	m^3 per customer
5	Normalize average use-monthly	Actual average use − weather adjustment.	2024 Weather Normalized: Table 11	m^3 per customer
6	Calculate normalized volume / throughput-monthly	Normalized average use × actual customers ÷ 1,000.	2024 Weather Normalized: Table 12	10^3 m^3
7	Calculate annual total volumes/throughputs	Sum the 12 monthly normalized volumes.	2024 Weather Normalized: Table 12	10^3 m^3
8	Roll normalized volumes to rate class	Sum monthly and annual Region + Rate Class + Sector volumes by Rate Class.	2024 Weather Normalized: Table 13	10^3 m^3 by rate class

Live worked example

Central | Rate 1 | Residential | January 2024

Metric	Tab names	Cell	Live result	Units
Actual customers	2024 Actuals	G8	1,612,309	customers
Unnormalized volume	2024 Actuals	G56	580,422	10^3 m^3
Actual average use	2024 Actuals	G104	360	m^3/customer
Actual HDD	2024 HDD	G8	533	HDD
Forecast HDD	2024 HDD	G22	586	HDD
HDD variance	2024 HDD	G36	-53	HDD
Weather factor	2024 Weather Factors	G7	0.678461	m^3/customer/HDD
Weather adjustment			-36	m^3/customer
Normalized average use	2024 Weather Normalized	G9	396	m^3/customer
Normalized volume / throughput	2024 Weather Normalized	G40	638,179	10^3 m^3

Table 1
2024 Actual General Service Customers by Region, Rate Class and Sector

Line No.	Region	Rate Class	Sector	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Annual Average
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	1,612,309	1,613,283	1,614,234	1,614,936	1,614,597	1,614,805	1,615,395	1,615,748	1,616,668	1,619,364	1,621,810	1,622,946	1,616,341
2	Central	Rate 6	Apartment	5,631	5,637	5,630	5,634	5,639	5,642	5,637	5,619	5,618	5,630	5,632	5,632	5,632
3	Central	Rate 6	Commercial	125,923	125,897	125,784	125,503	125,267	125,110	124,948	124,881	125,505	126,469	127,149	127,597	125,836
4	Central	Rate 6	Industrial	5,158	5,148	5,138	5,131	5,122	5,096	5,085	5,072	5,063	5,091	5,108	5,127	5,112
5	East	Rate 1	Residential	373,096	373,565	373,950	374,370	374,429	374,677	374,807	375,103	375,208	376,072	376,924	377,592	374,983
6	East	Rate 6	Apartment	1,253	1,253	1,227	1,215	1,218	1,219	1,219	1,220	1,219	1,220	1,219	1,216	1,225
7	East	Rate 6	Commercial	21,587	21,584	21,548	21,535	21,551	21,547	21,511	21,508	21,803	22,020	22,099	22,154	21,704
8	East	Rate 6	Industrial	163	164	164	165	164	162	162	162	162	162	162	162	163
9	West	Rate 1	Residential	169,283	169,441	169,559	169,726	169,649	169,742	169,887	169,968	170,027	170,335	170,661	170,796	169,923
10	West	Rate 6	Apartment	461	461	461	462	464	465	463	464	463	463	463	463	463
11	West	Rate 6	Commercial	11,040	11,056	11,047	11,025	11,026	10,997	10,986	10,974	11,071	11,154	11,221	11,257	11,071
12	West	Rate 6	Industrial	270	269	269	269	271	271	271	270	270	271	271	272	270
13	South	Rate M1	Residential	1,113,143	1,114,628	1,115,035	1,117,732	1,117,526	1,118,238	1,122,049	1,120,079	1,119,889	1,120,555	1,117,882	1,121,598	1,118,196
14	South	Rate M1	Commercial	81,814	81,742	81,685	81,675	81,543	81,588	81,710	80,798	80,917	80,946	80,716	81,367	81,375
15	South	Rate M1	Industrial	3,728	3,706	3,712	3,713	3,686	3,708	3,704	3,637	3,624	3,646	3,628	3,669	3,680
16	South	Rate M2	Residential	113	116	116	117	115	113	124	121	123	183	180	176	133
17	South	Rate M2	Commercial	7,285	7,315	7,351	7,389	7,368	7,373	7,420	7,974	8,037	8,099	8,124	8,300	7,670
18	South	Rate M2	Industrial	1,326	1,330	1,328	1,341	1,322	1,316	1,319	1,381	1,370	1,370	1,361	1,383	1,346
19	North	Rate 01	Residential	340,454	340,564	341,286	341,379	341,398	341,826	342,142	342,055	342,120	342,453	341,387	342,459	341,627
20	North	Rate 01	Commerical	29,047	29,023	29,033	28,974	28,948	28,968	28,879	28,736	28,808	28,862	28,824	28,934	28,920
21	North	Rate 10	Commercial	2,281	2,270	2,285	2,294	2,285	2,312	2,445	2,512	2,519	2,472	2,492	2,518	2,390
22	North	Rate 10	Industrial	147	150	149	152	150	147	165	167	174	172	176	177	161
23	EGI			3,905,512	3,908,602	3,910,991	3,914,737	3,913,738	3,915,322	3,920,328	3,918,449	3,920,658	3,927,009	3,927,489	3,935,795	3,918,219

Table 2
2024 Actual General Service Customers by Rate Class

Line No.	Rate Class	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Annual Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	2,154,688	2,156,289	2,157,743	2,159,032	2,158,675	2,159,224	2,160,089	2,160,819	2,161,903	2,165,771	2,169,395	2,171,334	2,161,247
2	Rate 6	171,486	171,469	171,268	170,939	170,722	170,509	170,282	170,170	171,174	172,480	173,324	173,880	171,475
3	Rate M1	1,198,685	1,200,076	1,200,432	1,203,120	1,202,755	1,203,534	1,207,463	1,204,514	1,204,430	1,205,147	1,202,226	1,206,634	1,203,251
4	Rate M2	8,724	8,761	8,795	8,847	8,805	8,802	8,863	9,476	9,530	9,652	9,665	9,859	9,148
5	Rate 01	369,501	369,587	370,319	370,353	370,346	370,794	371,021	370,791	370,928	371,315	370,211	371,393	370,547
6	Rate 10	2,428	2,420	2,434	2,446	2,435	2,459	2,610	2,679	2,693	2,644	2,668	2,695	2,551
7	EGI	3,905,512	3,908,602	3,910,991	3,914,737	3,913,738	3,915,322	3,920,328	3,918,449	3,920,658	3,927,009	3,927,489	3,935,795	3,918,219

Table 3

2024 Actual General Service Unnormalized Volumes by Region, Rate Class and Sector (10^3m^3)

Line No.	Region	Rate Class	Sector	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Annual Total
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	580,422	503,441	451,511	279,498	113,748	101,716	112,837	95,535	105,117	178,767	374,209	570,688	3,467,488
2	Central	Rate 6	Apartment	219,665	129,160	105,130	81,975	36,841	29,946	18,047	21,864	27,142	37,216	90,234	126,028	923,247
3	Central	Rate 6	Commercial	249,436	387,019	316,512	215,495	91,171	59,396	53,584	53,422	68,817	94,546	230,501	369,158	2,189,058
4	Central	Rate 6	Industrial	85,884	54,860	42,154	20,164	11,288	8,828	3,762	7,644	10,152	14,675	32,634	51,299	343,344
5	East	Rate 1	Residential	186,286	102,308	81,633	52,838	17,726	16,923	19,019	16,695	17,945	39,172	69,665	117,162	737,372
6	East	Rate 6	Apartment	23,754	12,799	9,378	8,121	2,945	1,754	1,199	1,289	2,169	4,068	8,973	13,387	89,836
7	East	Rate 6	Commercial	138,779	40,947	53,001	34,652	12,115	7,619	6,675	7,756	10,753	17,225	40,702	68,149	438,373
8	East	Rate 6	Industrial	9,295	4,991	2,828	1,600	(86)	842	280	783	790	1,218	3,294	3,094	28,930
9	West	Rate 1	Residential	81,606	44,508	39,642	23,848	9,075	8,408	9,051	7,842	8,416	14,492	31,250	49,531	327,670
10	West	Rate 6	Apartment	4,004	1,968	1,975	1,637	531	511	241	304	657	632	1,693	2,335	16,488
11	West	Rate 6	Commercial	47,508	28,988	24,248	16,299	7,016	5,729	4,162	4,363	6,064	7,563	17,319	28,779	198,038
12	West	Rate 6	Industrial	15,702	11,378	6,876	5,125	2,166	1,392	116	1,246	1,985	2,862	5,816	9,047	63,711
13	South	Rate M1	Residential	385,796	302,193	265,855	157,384	77,310	70,713	69,449	64,851	63,783	105,952	211,199	351,256	2,125,741
14	South	Rate M1	Commercial	117,869	91,641	86,600	48,873	23,391	16,234	15,081	14,751	15,157	28,635	65,973	96,741	620,945
15	South	Rate M1	Industrial	9,671	9,838	8,105	4,657	1,452	353	731	592	854	1,532	5,021	8,519	51,324
16	South	Rate M2	Residential	751	(8)	387	(8)	120	(38)	(31)	31	178	627	313	270	2,591
17	South	Rate M2	Commercial	144,662	115,325	97,233	62,136	32,496	27,588	23,243	32,528	30,892	65,652	104,123	127,869	863,748
18	South	Rate M2	Industrial	49,480	39,099	31,961	26,341	14,491	11,447	10,653	12,496	11,656	17,989	28,745	39,874	294,232
19	North	Rate 01	Residential	116,358	92,586	85,488	56,522	25,505	15,159	16,443	15,083	14,455	35,611	68,913	105,397	647,520
20	North	Rate 01	Commerical	43,517	34,393	33,227	22,253	11,063	4,675	4,452	5,376	3,856	11,576	24,070	34,997	233,455
21	North	Rate 10	Commercial	36,745	32,722	25,368	20,439	13,184	4,100	8,410	5,727	8,043	18,424	26,253	38,185	237,600
22	North	Rate 10	Industrial	6,883	7,678	4,487	5,126	3,068	14,255	(9,363)	2,773	2,481	5,912	4,416	13,797	61,513
23	EGI			2,554,075	2,047,832	1,773,599	1,144,972	506,615	407,550	368,043	372,951	411,364	704,345	1,445,313	2,225,562	13,962,223

Table 4

2024 Actual General Service Unnormalized Volumes by Rate Class (10^3m^3)

Line No.	Rate Class	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	848,313	650,257	572,787	356,184	140,549	127,046	140,908	120,072	131,478	232,431	475,123	737,381	4,532,530
2	Rate 6	794,029	672,109	562,100	385,067	163,987	116,018	88,066	98,672	128,530	180,005	431,165	671,277	4,291,025
3	Rate M1	513,336	403,672	360,560	210,914	102,152	87,301	85,261	80,194	79,794	136,118	282,193	456,515	2,798,010
4	Rate M2	194,894	154,415	129,581	88,468	47,107	38,996	33,866	45,055	42,726	84,269	133,181	168,013	1,160,571
5	Rate 01	159,875	126,980	118,715	78,775	36,568	19,834	20,895	20,458	18,312	47,187	92,982	140,394	880,975
6	Rate 10	43,628	40,400	29,856	25,565	16,252	18,355	(953)	8,500	10,524	24,335	30,668	51,982	299,113
7	EGI	2,554,075	2,047,832	1,773,599	1,144,972	506,615	407,550	368,043	372,951	411,364	704,345	1,445,313	2,225,562	13,962,223

Table 5

2024 Actual General Service Unnormalized Average Use by Region, Rate Class and Sector (m^3)

Line No.	Region	Rate Class	Sector	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Annual Total
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	360	312	280	173	70	63	70	59	65	110	231	352	2,145
2	Central	Rate 6	Apartment	39,010	22,913	18,673	14,550	6,533	5,308	3,202	3,891	4,831	6,610	16,022	22,377	163,920
3	Central	Rate 6	Commercial	1,981	3,074	2,516	1,717	728	475	429	428	548	748	1,813	2,893	17,349
4	Central	Rate 6	Industrial	16,651	10,657	8,204	3,930	2,204	1,732	740	1,507	2,005	2,882	6,389	10,006	66,907
5	East	Rate 1	Residential	499	274	218	141	47	45	51	45	48	104	185	310	1,967
6	East	Rate 6	Apartment	18,958	10,215	7,643	6,684	2,418	1,439	984	1,057	1,780	3,334	7,361	11,009	72,880
7	East	Rate 6	Commercial	6,429	1,897	2,460	1,609	562	354	310	361	493	782	1,842	3,076	20,175
8	East	Rate 6	Industrial	57,027	30,435	17,242	9,697	(523)	5,199	1,727	4,835	4,876	7,521	20,331	19,100	177,467
9	West	Rate 1	Residential	482	263	234	141	53	50	53	46	49	85	183	290	1,929
10	West	Rate 6	Apartment	8,686	4,268	4,283	3,543	1,144	1,100	520	655	1,419	1,364	3,657	5,044	35,684
11	West	Rate 6	Commercial	4,303	2,622	2,195	1,478	636	521	379	398	548	678	1,543	2,557	17,858
12	West	Rate 6	Industrial	58,156	42,299	25,560	19,052	7,994	5,137	427	4,613	7,353	10,563	21,460	33,259	235,873
13	South	Rate M1	Residential	347	271	238	141	69	63	62	58	57	95	189	313	1,903
14	South	Rate M1	Commercial	1,441	1,121	1,060	598	287	199	185	183	187	354	817	1,189	7,621
15	South	Rate M1	Industrial	2,594	2,655	2,183	1,254	394	95	197	163	236	420	1,384	2,322	13,897
16	South	Rate M2	Residential	6,649	(71)	3,336	(71)	1,039	(340)	(247)	260	1,444	3,426	1,737	1,534	18,696
17	South	Rate M2	Commercial	19,858	15,766	13,227	8,409	4,410	3,742	3,132	4,079	3,844	8,106	12,817	15,406	112,796
18	South	Rate M2	Industrial	37,316	29,398	24,067	19,642	10,961	8,698	8,077	9,048	8,508	13,131	21,121	28,832	218,798
19	North	Rate 01	Residential	342	272	250	166	75	44	48	44	42	104	202	308	1,897
20	North	Rate 01	Commerical	1,498	1,185	1,144	768	382	161	154	187	134	401	835	1,210	8,060
21	North	Rate 10	Commercial	16,109	14,415	11,102	8,910	5,770	1,773	3,440	2,280	3,193	7,453	10,535	15,165	100,144
22	North	Rate 10	Industrial	46,822	51,184	30,117	33,725	20,454	96,975	(56,747)	16,605	14,261	34,371	25,090	77,950	390,806
23	EGI			654	524	453	292	129	104	94	95	105	179	368	565	3,564

Table 6

2024 Actual General Service Unnormalized Average Use by Rate Class (m^3)

Line No.	Rate Class	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	394	302	265	165	65	59	65	56	61	107	219	340	2,097
2	Rate 6	4,630	3,920	3,282	2,253	961	680	517	580	751	1,044	2,488	3,861	24,965
3	Rate M1	428	336	300	175	85	73	71	67	66	113	235	378	2,327
4	Rate M2	22,340	17,625	14,733	10,000	5,350	4,430	3,821	4,755	4,483	8,731	13,780	17,042	127,090
5	Rate 01	433	344	321	213	99	53	56	55	49	127	251	378	2,379
6	Rate 10	17,969	16,694	12,266	10,452	6,674	7,465	(365)	3,173	3,908	9,204	11,495	19,288	118,223
7	EGI	654	524	453	292	129	104	94	95	105	179	368	565	3,564

Table 7
2024 Actual Heating Degree Days (HDDs)

Line No.	Weather Zone	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	533	427	348	190	16	4	-	1	4	111	265	482	2,381
2	East	647	535	404	240	34	7	-	2	15	178	338	626	3,026
3	West	501	403	327	182	23	3	-	-	2	100	247	449	2,237
4	South	561	438	362	181	28	7	-	3	8	137	282	506	2,511
5	North	659	551	457	284	75	18	1	7	23	194	358	613	3,239

Table 8
2024 Forecast HDDs

Line No.	Weather Zone	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	586	532	424	232	56	-	-	-	-	128	319	487	2,764
2	East	738	644	522	282	55	-	-	-	10	185	421	622	3,479
3	West	545	499	406	245	58	-	-	-	-	104	305	443	2,605
4	South	610	556	443	265	64	-	-	-	-	148	359	496	2,941
5	North	740	672	550	346	112	-	-	-	30	219	440	637	3,746

Table 9
2024 HDD Variance (Actual vs Forecast)

Line No.	Weather Zone	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	(53)	(105)	(76)	(42)	(40)	4	-	1	4	(17)	(54)	(6)	(383)
2	East	(91)	(109)	(118)	(43)	(21)	7	-	2	5	(7)	(83)	4	(453)
3	West	(44)	(96)	(79)	(63)	(35)	3	-	-	2	(4)	(58)	5	(368)
4	South	(49)	(118)	(81)	(84)	(36)	7	-	3	8	(11)	(77)	10	(430)
5	North	(81)	(121)	(93)	(62)	(38)	18	1	7	(7)	(25)	(82)	(24)	(507)

Table 10
2024 General Service Weather Factors

Line No.	Region	Rate Class	Sector	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Central	Rate 1	Residential	0.678461	0.64145	0.668676	0.668628	0.793357	0	0	0	0.606589	0.577939	0.647502	0.649146
2	Central	Rate 6	Apartment	32.98354	35.88974	37.61371	46.62484	64.89911	0	0	0	0	14.74065	24.44227	29.79446
3	Central	Rate 6	Commercial	4.681155	4.961372	5.356947	5.434814	6.258418	0	0	0	0	2.589133	3.89646	4.358119
4	Central	Rate 6	Industrial	16.75416	19.13193	21.06842	21.1506	21.26923	0	0	0	0	8.374085	14.02995	17.80188
5	East	Rate 1	Residential	0.488818	0.472474	0.488543	0.486057	0.527852	0	0	0	0.341843	0.390038	0.447663	0.466529
6	East	Rate 6	Apartment	13.88678	14.95768	15.68398	18.91168	27.05826	0	0	0	0	8.082533	11.92122	12.59253
7	East	Rate 6	Commercial	3.956679	4.467559	4.65816	4.757094	5.49348	0	0	0	0	2.03977	3.252347	3.796953
8	East	Rate 6	Industrial	34.41172	43.73305	40.32668	47.69056	55.43908	0	0	0	0	15.75561	27.28348	31.85669
9	West	Rate 1	Residential	0.614502	0.590587	0.612862	0.600763	0.681843	0	0	0	0.742095	0.517075	0.581439	0.59066
10	West	Rate 6	Apartment	9.266807	9.250838	10.41383	10.87257	12.9749	0	0	0	0	7.697319	9.293349	8.875446
11	West	Rate 6	Commercial	4.125778	4.310841	4.636826	4.724999	5.313023	0	0	0	0	2.373805	3.372379	3.885515
12	West	Rate 6	Industrial	41.92406	52.74379	55.51871	73.6871	86.58599	0	0	0	0	14.29466	37.58979	38.78978
13	South	Rate M1	Residential	0.573379	0.538316	0.554522	0.528277	0.499266	0	0	0	0	0.338146	0.489492	0.558701
14	South	Rate M1	Commercial	2.221691	2.267305	2.355236	2.107732	1.986641	0	0	0	0	1.511635	2.341938	2.377596
15	South	Rate M1	Industrial	5.261479	5.814744	5.952488	4.813124	3.57358	0	0	0	0	4.586956	5.818748	6.493708
16	South	Rate M2	Residential	16.71965	15.11175	19.82594	2.584414	30.03631	0	0	0	0	18.99085	13.46486	9.749721
17	South	Rate M2	Commercial	27.25072	29.26723	32.8618	33.7741	43.45692	0	0	0	29.42999	39.57563	36.25397	30.85559
18	South	Rate M2	Industrial	43.54794	48.59668	47.51066	44.73587	38.32417	0	0	0	67.58234	55.51093	49.70189	50.7681
19	North	Rate 01	Residential	0.512486	0.458217	0.470531	0.457815	0.459918	0	0	0	0.171716	0.359481	0.469169	0.473894
20	North	Rate 01	Commerical	2.039736	1.885203	1.9664	1.686936	1.544531	0	0	0	0	1.285278	1.815177	1.911705
21	North	Rate 10	Commercial	21.64333	21.53042	21.80052	21.43946	23.7998	0	0	0	15.17898	22.44356	23.41299	22.09244
22	North	Rate 10	Industrial	62.50662	66.69214	65.31742	57.32447	78.25851	0	0	0	79.4323	67.86625	69.22231	68.09875

Table 11
2024 Actual Weather Normalized Average Use by Region, Rate Class and Sector (m^3)
Normalized to 2024 Forecast Heating Degree Days (HDDs)

Line No.	Region	Rate Class	Sector	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Annual Total
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	396	379	330	201	102	63	70	59	63	120	266	355	2,404
2	Central	Rate 6	Apartment	40,751	26,681	21,528	16,504	9,103	5,308	3,202	3,891	4,831	6,855	17,342	22,541	178,537
3	Central	Rate 6	Commercial	2,228	3,595	2,923	1,945	976	475	429	428	548	791	2,023	2,917	19,277
4	Central	Rate 6	Industrial	17,535	12,665	9,803	4,816	3,046	1,732	740	1,507	2,005	3,022	7,146	10,104	74,122
5	East	Rate 1	Residential	544	325	276	162	59	45	51	45	46	107	222	308	2,189
6	East	Rate 6	Apartment	20,221	11,840	9,489	7,487	2,994	1,439	984	1,057	1,780	3,387	8,346	10,960	79,985
7	East	Rate 6	Commercial	6,789	2,383	3,008	1,811	679	354	310	361	493	796	2,110	3,061	22,155
8	East	Rate 6	Industrial	60,159	35,189	21,988	11,724	658	5,199	1,727	4,835	4,876	7,625	22,584	18,976	195,540
9	West	Rate 1	Residential	509	319	282	178	77	50	53	46	48	87	217	287	2,154
10	West	Rate 6	Apartment	9,094	5,156	5,102	4,226	1,601	1,100	520	655	1,419	1,397	4,199	4,995	39,463
11	West	Rate 6	Commercial	4,485	3,035	2,559	1,775	823	521	379	398	548	688	1,740	2,535	19,487
12	West	Rate 6	Industrial	60,005	47,357	29,924	23,679	11,041	5,137	427	4,613	7,353	10,623	23,652	33,046	256,857
13	South	Rate M1	Residential	375	335	284	185	87	63	62	58	57	98	227	308	2,138
14	South	Rate M1	Commercial	1,550	1,389	1,252	775	359	199	185	183	187	371	997	1,166	8,613
15	South	Rate M1	Industrial	2,854	3,342	2,667	1,658	523	95	197	163	236	472	1,831	2,259	16,298
16	South	Rate M2	Residential	7,475	1,716	4,948	146	2,127	(340)	(247)	260	1,444	3,641	2,771	1,439	25,379
17	South	Rate M2	Commercial	21,204	19,225	15,899	11,246	5,984	3,742	3,132	4,079	3,608	8,553	15,601	15,107	127,380
18	South	Rate M2	Industrial	39,467	35,142	27,930	23,400	12,349	8,698	8,077	9,048	7,968	13,758	24,938	28,339	239,113
19	North	Rate 01	Residential	383	327	294	194	92	44	48	44	43	113	240	319	2,143
20	North	Rate 01	Commerical	1,663	1,413	1,328	873	440	161	154	187	134	433	983	1,255	9,025
21	North	Rate 10	Commercial	17,856	17,020	13,134	10,247	6,662	1,773	3,440	2,280	3,298	8,012	12,448	15,691	111,860
22	North	Rate 10	Industrial	51,867	59,254	36,204	37,302	23,389	96,975	(56,747)	16,605	14,809	36,061	30,745	79,570	426,034

Table 12
2024 Actual Weather Normalized Volumes by Region, Rate Class and Sector (10^3m^3)
Normalized to 2024 Forecast HDDs

Line No.	Region	Rate Class	Sector	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Annual Total
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	638,179	612,099	533,438	324,741	164,473	101,716	112,837	95,535	101,194	194,303	430,916	576,482	3,885,913
2	Central	Rate 6	Apartment	229,472	150,403	121,203	92,981	51,333	29,946	18,047	21,864	27,142	38,594	97,667	126,951	1,005,602
3	Central	Rate 6	Commercial	280,560	452,604	367,655	244,074	122,217	59,396	53,584	53,422	68,817	99,982	257,254	372,217	2,431,782
4	Central	Rate 6	Industrial	90,447	65,201	50,370	24,711	15,602	8,828	3,762	7,644	10,152	15,382	36,504	51,801	380,405
5	East	Rate 1	Residential	202,882	121,493	103,136	60,572	21,936	16,923	19,019	16,695	17,252	40,140	83,602	116,475	820,125
6	East	Rate 6	Apartment	25,337	14,836	11,643	9,097	3,647	1,754	1,199	1,289	2,169	4,133	10,174	13,328	98,606
7	East	Rate 6	Commercial	146,552	51,428	64,815	39,006	14,637	7,619	6,675	7,756	10,753	17,521	46,638	67,821	481,222
8	East	Rate 6	Industrial	9,806	5,771	3,606	1,934	108	842	280	783	790	1,235	3,659	3,074	31,888
9	West	Rate 1	Residential	86,193	54,105	47,810	30,251	13,147	8,408	9,051	7,842	8,151	14,862	37,035	48,977	365,832
10	West	Rate 6	Apartment	4,193	2,377	2,352	1,952	743	511	241	304	657	647	1,944	2,313	18,233
11	West	Rate 6	Commercial	49,517	33,558	28,274	19,570	9,078	5,729	4,162	4,363	6,064	7,675	19,525	28,538	216,053
12	West	Rate 6	Industrial	16,201	12,739	8,050	6,370	2,992	1,392	116	1,246	1,985	2,879	6,410	8,988	69,367
13	South	Rate M1	Residential	417,325	373,116	316,124	206,984	97,507	70,713	69,449	64,851	63,783	110,233	253,223	345,178	2,388,487
14	South	Rate M1	Commercial	126,848	113,547	102,242	63,333	29,255	16,234	15,081	14,751	15,157	30,017	80,491	94,864	701,821
15	South	Rate M1	Industrial	10,640	12,385	9,901	6,158	1,929	353	731	592	854	1,721	6,642	8,288	60,193
16	South	Rate M2	Residential	845	199	574	17	245	(38)	(31)	31	178	666	499	253	3,438
17	South	Rate M2	Commercial	154,469	140,630	116,872	83,099	44,087	27,588	23,243	32,528	29,000	69,274	126,743	125,385	972,919
18	South	Rate M2	Industrial	52,333	46,738	37,091	31,380	16,325	11,447	10,653	12,496	10,916	18,849	33,940	39,193	321,360
19	North	Rate 01	Residential	130,438	111,468	100,455	66,275	31,393	15,159	16,443	15,083	14,861	38,677	81,998	109,260	731,509
20	North	Rate 01	Commerical	48,298	41,014	38,548	25,303	12,739	4,675	4,452	5,376	3,856	12,499	28,344	36,313	261,419
21	North	Rate 10	Commercial	40,729	38,636	30,011	23,508	15,223	4,100	8,410	5,727	8,307	19,805	31,019	39,509	264,984
22	North	Rate 10	Industrial	7,624	8,888	5,394	5,670	3,508	14,255	(9,363)	2,773	2,577	6,202	5,411	14,084	67,025
23	EGI			2,768,890	2,463,237	2,099,562	1,366,986	672,124	407,550	368,043	372,951	404,615	745,296	1,679,639	2,229,291	15,578,184

Table 13
2024 Actual Weather Normalized Volumes by Rate Class (10^3m^3)
Normalized to 2024 Forecast HDDs

Line No.	Rate Class	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Sep-2024	Oct-2024	Nov-2024	Dec-2024	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	927,255	787,697	684,383	415,564	199,556	127,046	140,908	120,072	126,598	249,304	551,553	741,934	**5,071,871**
2	Rate 6	852,085	788,918	657,967	439,696	220,356	116,018	88,066	98,672	128,530	188,047	479,775	675,031	**4,733,161**
3	Rate M1	554,813	499,048	428,267	276,475	128,691	87,301	85,261	80,194	79,794	141,971	340,356	448,329	**3,150,501**
4	Rate M2	207,647	187,568	154,537	114,495	60,657	38,996	33,866	45,055	40,093	88,789	161,182	164,831	**1,297,716**
5	Rate 01	178,737	152,482	139,003	91,578	44,132	19,834	20,895	20,458	18,717	51,176	110,343	145,573	**992,927**
6	Rate 10	48,354	47,524	35,406	29,178	18,732	18,355	(953)	8,500	10,884	26,008	36,431	53,593	**332,009**
7	EGI	2,768,890	2,463,237	2,099,562	1,366,986	672,124	407,550	368,043	372,951	404,615	745,296	1,679,639	2,229,291	**15,578,184**

Determination of Actual Normalized Volumes / Throughputs

with live worked example (Rate 1, Central) for normalization to 2025 forecast HDDs

Method in one line

Normalized volume (10^3 m^3) = [Actual average use − Weather factor × (Actual HDD − Forecast HDD)] × Actual customers ÷ 1,000

Calculation steps

Step	Calculation	What to do	Workbook source	Output / units
1	Identify the segment	Use the exact Region + Rate Class + Sector and month.	2025 Actuals / 2025 Weather Factors	One unique record
2	Calculate actual average use-monthly	Unnormalized volume × 1,000 ÷ actual customer count.	2025 Actuals: Tables 1, 3 and 5	m^3 per customer
3	Calculate HDD variance-monthly	Actual HDD − Forecast HDD for the segment's weather zone.	2025 HDD: Table 9	HDD
4	Calculate weather adjustment-monthly	Weather factor × HDD variance.	2025 Weather Factors: Table 10	m^3 per customer
5	Normalize average use-monthly	Actual average use − weather adjustment.	2025 Weather Normalized: Table 11	m^3 per customer
6	Calculate normalized volume / throughput-monthly	Normalized average use × actual customers ÷ 1,000.	2025 Weather Normalized: Table 12	10^3 m^3
7	Calculate annual total volumes/throughputs	Sum the 12 monthly normalized volumes.	2025 Weather Normalized: Table 12	10^3 m^3
8	Roll normalized volumes to rate class	Sum monthly and annual Region + Rate Class + Sector volumes by Rate Class.	2025 Weather Normalized: Table 13	10^3 m^3 by rate class

Live worked example

Central | Rate 1 | Residential | January 2025

Metric	Tab names	Cell	Live result	Units
Actual customers	2025 Actuals	G8	1,624,660	customers
Unnormalized volume	2025 Actuals	G56	741,321.3	10^3 m^3
Actual average use	2025 Actuals	G104	456	m^3/customer
Actual HDD	2025 HDD	G8	634	HDD
Forecast HDD	2025 HDD	G22	581	HDD
HDD variance	2025 HDD	G36	53	HDD
Weather factor	2025 Weather Factors	G7	0.671821	m^3/customer/HDD
Weather adjustment			35	m^3/customer
Normalized average use	2025 Weather Normalized	G9	421	m^3/customer
Normalized volume / throughput	2025 Weather Normalized	G40	684,019	10^3 m^3

Table 1
2025 Actual General Service Customers by Region, Rate Class and Sector

Line No.	Region	Rate Class	Sector	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Average
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	1,624,660	1,625,470	1,626,048	1,626,744	1,626,526	1,626,172	1,626,424	1,627,052	1,628,189	1,630,696	1,633,079	1,634,495	1,627,963
2	Central	Rate 6	Apartment	5,640	5,635	5,635	5,635	5,638	5,639	5,645	5,643	5,641	5,647	5,648	5,647	5,641
3	Central	Rate 6	Commercial	127,933	128,002	127,930	127,843	127,445	127,187	127,091	127,169	127,284	127,918	128,595	128,936	127,778
4	Central	Rate 6	Industrial	5,138	5,131	5,130	5,125	5,114	5,092	5,083	5,082	5,090	5,107	5,136	5,135	5,114
5	East	Rate 1	Residential	378,032	378,404	378,963	379,245	379,385	379,632	379,900	380,385	380,892	381,744	382,438	382,949	380,164
6	East	Rate 6	Apartment	1,223	1,225	1,226	1,224	1,226	1,229	1,230	1,232	1,232	1,233	1,234	1,233	1,229
7	East	Rate 6	Commercial	22,179	22,201	22,189	22,161	22,119	22,096	22,060	22,048	22,051	22,135	22,207	22,254	22,142
8	East	Rate 6	Industrial	163	163	163	162	162	162	162	162	162	162	162	163	162
9	West	Rate 1	Residential	170,959	171,106	171,180	171,230	171,167	171,124	171,156	171,268	171,307	171,588	171,905	172,101	171,341
10	West	Rate 6	Apartment	466	467	468	469	468	468	468	468	469	468	468	470	468
11	West	Rate 6	Commercial	11,259	11,273	11,263	11,268	11,210	11,202	11,197	11,203	11,203	11,254	11,293	11,307	11,244
12	West	Rate 6	Industrial	271	270	270	268	268	268	268	268	268	267	269	269	269
13	South	Rate M1	Residential	1,122,668	1,122,667	1,123,820	1,126,025	1,125,588	1,126,412	1,128,322	1,128,309	1,128,740	1,130,950	1,129,628	1,129,817	1,126,912
14	South	Rate M1	Commercial	81,581	81,638	81,435	81,444	81,225	81,394	81,509	81,597	82,110	82,733	82,876	82,992	81,878
15	South	Rate M1	Industrial	3,704	3,695	3,654	3,652	3,636	3,631	3,628	3,629	3,702	3,762	3,778	3,798	3,689
16	South	Rate M2	Residential	181	204	192	193	193	143	104	79	81	50	44	43	126
17	South	Rate M2	Commercial	8,508	8,657	8,463	8,471	8,380	8,228	8,131	8,052	7,561	7,198	7,238	7,244	8,011
18	South	Rate M2	Industrial	1,397	1,424	1,381	1,380	1,352	1,362	1,362	1,354	1,287	1,214	1,236	1,236	1,332
19	North	Rate 01	Residential	342,758	342,769	343,008	343,420	343,375	343,582	344,112	343,997	344,104	344,662	344,429	344,417	343,719
20	North	Rate 01	Commerical	29,069	29,108	29,019	28,967	28,908	28,914	29,000	29,067	29,260	29,501	29,514	29,582	29,159
21	North	Rate 10	Commercial	2,584	2,624	2,568	2,560	2,525	2,534	2,454	2,431	2,205	2,072	2,083	2,069	2,392
22	North	Rate 10	Industrial	179	184	176	175	173	172	172	169	159	156	159	163	170
23	EGI			3,940,552	3,942,317	3,944,181	3,947,661	3,946,083	3,946,643	3,949,478	3,950,664	3,952,997	3,960,517	3,963,419	3,966,320	3,950,903

Table 2
2025 Actual General Service Customers by Rate Class

Line No.	Rate Class	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	2,173,651	2,174,980	2,176,191	2,177,219	2,177,078	2,176,928	2,177,480	2,178,705	2,180,388	2,184,028	2,187,422	2,189,545	2,179,468
2	Rate 6	174,272	174,367	174,274	174,155	173,650	173,343	173,204	173,275	173,400	174,191	175,012	175,414	174,046
3	Rate M1	1,207,953	1,208,000	1,208,909	1,211,121	1,210,449	1,211,437	1,213,459	1,213,535	1,214,552	1,217,445	1,216,282	1,216,607	1,212,479
4	Rate M2	10,086	10,285	10,036	10,044	9,925	9,733	9,597	9,485	8,929	8,462	8,518	8,523	9,469
5	Rate 01	371,827	371,877	372,027	372,387	372,283	372,496	373,112	373,064	373,364	374,163	373,943	373,999	372,879
6	Rate 10	2,763	2,808	2,744	2,735	2,698	2,706	2,626	2,600	2,364	2,228	2,242	2,232	2,562
7	EGI	3,940,552	3,942,317	3,944,181	3,947,661	3,946,083	3,946,643	3,949,478	3,950,664	3,952,997	3,960,517	3,963,419	3,966,320	3,950,903

Table 3
2025 Actual General Service Unnormalized Volumes by Region, Rate Class and Sector (10^3m^3)

Line No.	Region	Rate Class	Sector	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	741,321	608,682	488,585	319,891	185,143	81,745	122,778	94,913	99,278	192,254	445,902	651,434	4,031,925
2	Central	Rate 6	Apartment	177,564	150,219	94,400	106,021	57,625	5,965	15,124	22,565	25,933	28,090	102,252	157,045	942,805
3	Central	Rate 6	Commercial	519,239	448,746	382,676	244,803	134,677	65,705	57,739	57,494	71,497	120,225	290,055	433,696	2,826,551
4	Central	Rate 6	Industrial	60,786	64,773	39,022	36,935	15,706	1,492	4,722	9,121	9,679	10,785	36,919	61,069	351,009
5	East	Rate 1	Residential	139,974	121,869	94,449	58,326	27,002	14,077	21,228	16,879	18,490	37,149	86,152	136,585	772,180
6	East	Rate 6	Apartment	16,863	15,334	10,185	9,663	5,581	(561)	561	1,958	1,771	2,535	10,770	15,906	90,566
7	East	Rate 6	Commercial	86,133	80,388	61,354	38,309	18,508	13,503	7,206	8,921	11,167	19,152	51,719	84,751	481,112
8	East	Rate 6	Industrial	4,648	4,346	2,511	3,638	670	(180)	204	714	855	950	2,914	5,396	26,665
9	West	Rate 1	Residential	66,120	55,133	41,685	28,792	14,828	6,533	9,947	7,965	8,219	16,568	37,211	57,122	350,122
10	West	Rate 6	Apartment	3,115	2,258	1,787	1,955	1,063	114	436	195	571	369	2,065	2,709	16,637
11	West	Rate 6	Commercial	36,668	32,897	28,275	19,061	10,292	5,052	4,196	5,699	6,031	10,507	20,688	33,002	212,369
12	West	Rate 6	Industrial	12,751	13,181	5,592	8,337	2,154	628	627	372	2,731	2,436	7,297	11,669	67,774
13	South	Rate M1	Residential	440,889	369,571	275,038	198,100	110,276	61,608	74,557	61,394	61,974	109,375	261,410	404,374	2,428,566
14	South	Rate M1	Commercial	133,160	93,719	86,736	60,457	25,606	10,495	17,106	12,550	16,817	31,885	87,369	117,237	693,137
15	South	Rate M1	Industrial	7,866	12,695	7,232	4,709	2,942	(745)	374	46	1,565	1,399	7,119	9,386	54,588
16	South	Rate M2	Residential	1,627	(766)	343	(420)	417	21	39	(129)	66	364	185	512	2,259
17	South	Rate M2	Commercial	144,271	144,047	101,174	89,425	60,265	25,275	34,304	24,867	38,538	68,934	115,238	149,365	995,703
18	South	Rate M2	Industrial	43,956	59,091	20,217	29,614	17,769	13,360	8,408	11,480	11,593	18,862	28,263	46,140	308,751
19	North	Rate 01	Residential	139,586	109,925	94,618	64,892	31,361	12,639	16,800	14,533	15,403	36,435	83,213	121,895	741,299
20	North	Rate 01	Commerical	53,435	33,224	35,687	24,116	9,475	3,734	5,580	4,964	5,225	12,605	29,686	44,117	261,850
21	North	Rate 10	Commercial	40,878	39,550	29,352	25,102	10,024	5,140	9,333	6,657	8,682	16,147	27,855	39,419	258,138
22	North	Rate 10	Industrial	6,557	11,795	3,093	3,690	5,319	2,372	1,400	(2,735)	9,376	4,438	6,291	7,151	58,747
23	EGI			2,877,406	2,470,676	1,904,013	1,375,415	746,701	327,972	412,667	360,423	425,465	741,465	1,740,572	2,589,980	15,972,755

Table 4
2025 Actual General Service Unnormalized Volumes by Rate Class (10^3m^3)

Line No.	Rate Class	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	947,415	785,684	624,719	407,009	226,973	102,355	153,953	119,757	125,988	245,971	569,265	845,141	5,154,228
2	Rate 6	917,767	812,143	625,803	468,721	246,276	91,719	90,813	107,039	130,237	195,050	524,679	805,243	5,015,489
3	Rate M1	581,915	475,985	369,006	263,266	138,824	71,357	92,037	73,989	80,356	142,659	355,898	530,997	3,176,291
4	Rate M2	189,853	202,371	121,734	118,619	78,450	38,655	42,751	36,218	50,198	88,161	143,686	196,017	1,306,713
5	Rate 01	193,021	143,149	130,305	89,008	40,836	16,373	22,380	19,497	20,628	49,040	112,899	166,013	1,003,149
6	Rate 10	47,435	51,345	32,446	28,792	15,342	7,512	10,733	3,922	18,059	20,585	34,146	46,570	316,885
7	EGI	2,877,406	2,470,676	1,904,013	1,375,415	746,701	327,972	412,667	360,423	425,465	741,465	1,740,572	2,589,980	15,972,755

Table 5

2025 Actual General Service Unnormalized Average Use by Region, Rate Class and Sector (m^3)

Line No.	Region	Rate Class	Sector	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	456	374	300	197	114	50	75	58	61	118	273	399	2,476
2	Central	Rate 6	Apartment	31,483	26,658	16,752	18,815	10,221	1,058	2,679	3,999	4,597	4,974	18,104	27,810	167,151
3	Central	Rate 6	Commercial	4,059	3,506	2,991	1,915	1,057	517	454	452	562	940	2,256	3,364	22,071
4	Central	Rate 6	Industrial	11,831	12,624	7,607	7,207	3,071	293	929	1,795	1,902	2,112	7,188	11,893	68,450
5	East	Rate 1	Residential	370	322	249	154	71	37	56	44	49	97	225	357	2,032
6	East	Rate 6	Apartment	13,789	12,518	8,307	7,895	4,553	(456)	456	1,589	1,437	2,056	8,728	12,900	73,771
7	East	Rate 6	Commercial	3,884	3,621	2,765	1,729	837	611	327	405	506	865	2,329	3,808	21,686
8	East	Rate 6	Industrial	28,515	26,664	15,403	22,454	4,135	(1,113)	1,260	4,409	5,277	5,867	17,985	33,103	163,960
9	West	Rate 1	Residential	387	322	244	168	87	38	58	47	48	97	216	332	2,043
10	West	Rate 6	Apartment	6,684	4,836	3,819	4,168	2,270	244	932	416	1,218	789	4,413	5,763	35,553
11	West	Rate 6	Commercial	3,257	2,918	2,510	1,692	918	451	375	509	538	934	1,832	2,919	18,852
12	West	Rate 6	Industrial	47,050	48,817	20,712	31,108	8,038	2,344	2,338	1,387	10,191	9,123	27,125	43,380	251,613
13	South	Rate M1	Residential	393	329	245	176	98	55	66	54	55	97	231	358	2,157
14	South	Rate M1	Commercial	1,632	1,148	1,065	742	315	129	210	154	205	385	1,054	1,413	8,453
15	South	Rate M1	Industrial	2,124	3,436	1,979	1,289	809	(205)	103	13	423	372	1,884	2,471	14,698
16	South	Rate M2	Residential	8,987	(3,755)	1,789	(2,177)	2,160	147	374	(1,637)	821	7,286	4,216	11,905	30,115
17	South	Rate M2	Commercial	16,957	16,639	11,955	10,557	7,191	3,072	4,219	3,088	5,097	9,577	15,921	20,619	124,893
18	South	Rate M2	Industrial	31,464	41,496	14,639	21,459	13,142	9,809	6,173	8,479	9,008	15,537	22,866	37,330	231,403
19	North	Rate 01	Residential	407	321	276	189	91	37	49	42	45	106	242	354	2,158
20	North	Rate 01	Commerical	1,838	1,141	1,230	833	328	129	192	171	179	427	1,006	1,491	8,965
21	North	Rate 10	Commercial	15,820	15,072	11,430	9,805	3,970	2,028	3,803	2,738	3,938	7,793	13,373	19,052	108,822
22	North	Rate 10	Industrial	36,631	64,103	17,576	21,084	30,743	13,790	8,139	(16,182)	58,972	28,447	39,565	43,873	346,740
23	EGI			730	627	483	348	189	83	104	91	108	187	439	653	4,043

Table 6

2025 Actual General Service Unnormalized Average Use by Rate Class (m^3)

Line No.	Rate Class	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	436	361	287	187	104	47	71	55	58	113	260	386	2,365
2	Rate 6	5,266	4,658	3,591	2,691	1,418	529	524	618	751	1,120	2,998	4,591	28,755
3	Rate M1	482	394	305	217	115	59	76	61	66	117	293	436	2,621
4	Rate M2	18,823	19,676	12,130	11,810	7,904	3,972	4,455	3,818	5,622	10,418	16,869	22,999	138,496
5	Rate 01	519	385	350	239	110	44	60	52	55	131	302	444	2,691
6	Rate 10	17,168	18,285	11,824	10,527	5,687	2,776	4,087	1,508	7,639	9,239	15,230	20,865	124,835
7	EGI	730	627	483	348	189	83	104	91	108	187	439	653	4,043

Table 7
2025 Actual Heating Degree Days (HDDs)

Line No.	Weather Zone	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	634	552	393	229	79	3	-	2	2	123	344	565	2,926
2	East	753	679	491	280	84	8	-	3	18	177	446	729	3,668
3	West	598	524	358	222	77	4	-	1	5	123	316	528	2,753
4	South	668	572	380	236	99	6	-	7	9	149	360	598	3,084
5	North	777	683	534	347	132	16	1	13	38	189	444	720	3,892

Table 8
2025 Forecast HDDs

Line No.	Weather Zone	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	581	530	420	230	55	-	-	-	-	126	316	482	2,740
2	East	733	642	518	280	55	-	-	-	9	183	418	618	3,456
3	West	544	501	405	244	58	-	-	-	-	104	305	442	2,603
4	South	608	558	442	264	64	-	-	-	-	147	358	494	2,935
5	North	739	674	549	346	111	-	-	-	29	218	439	636	3,741

Table 9
2025 HDD Variance (Actual vs Forecast)

Line No.	Weather Zone	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	53	22	(27)	(1)	24	3	-	2	2	(3)	28	83	186
2	East	20	37	(27)	0	29	8	-	3	9	(6)	28	111	212
3	West	54	22	(48)	(22)	19	4	-	1	5	19	11	86	150
4	South	60	14	(62)	(28)	35	6	-	7	9	2	1	104	149
5	North	38	9	(16)	1	21	16	1	13	9	(29)	5	84	151

Table 10
2025 General Service Weather Factors

Line No.	Region	Rate Class	Sector	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Central	Rate 1	Residential	0.671821	0.636966	0.660924	0.670891	0.777189	0	0	0	0.571530	0.573754	0.640190	0.646353
2	Central	Rate 6	Apartment	36.406765	42.058816	40.264948	59.780938	91.556691	0	0	0	0	14.989874	24.644975	33.200226
3	Central	Rate 6	Commercial	4.824911	4.856351	5.389400	4.993234	4.493818	0	0	0	0	3.154713	4.444924	4.597910
4	Central	Rate 6	Industrial	14.685022	19.392387	18.432514	24.951611	32.712523	0	0	0	0	5.521773	10.415358	14.597112
5	East	Rate 1	Residential	0.480873	0.471092	0.482728	0.491011	0.499131	0	0	0	0.300178	0.388410	0.433206	0.462579
6	East	Rate 6	Apartment	14.410109	16.500644	17.199384	23.200823	39.950726	0	0	0	0	4.095982	9.722424	11.821840
7	East	Rate 6	Commercial	4.131296	4.561429	4.749490	4.565589	4.008199	0	0	0	0	2.601907	3.625304	4.046657
8	East	Rate 6	Industrial	31.996593	36.623583	36.535632	64.193963	84.023697	0	0	0	0	14.698258	20.179537	32.302707
9	West	Rate 1	Residential	0.608460	0.586890	0.607583	0.608652	0.668336	0	0	0	0.668620	0.505531	0.569643	0.587120
10	West	Rate 6	Apartment	9.728547	9.467087	9.080482	13.303236	17.207976	0	0	0	0	2.444409	6.260039	7.299262
11	West	Rate 6	Commercial	4.107796	4.167344	4.654205	4.466002	4.754874	0	0	0	0	2.916111	3.781054	3.927709
12	West	Rate 6	Industrial	52.218079	66.095283	59.843624	92.174866	101.420833	0	0	0	0	22.981166	36.107392	48.574208
13	South	Rate M1	Residential	0.562187	0.533934	0.546526	0.528077	0.496846	0	0	0	0	0.335196	0.489050	0.552174
14	South	Rate M1	Commercial	2.261052	1.921730	2.099259	2.002715	1.697428	0	0	0	0.844649	1.444792	2.104824	2.036780
15	South	Rate M1	Industrial	2.430571	4.262802	4.011167	3.127230	4.834512	0	0	0	1.607164	2.112747	3.951802	3.801988
16	South	Rate M2	Residential	23.447749	11.701630	16.440773	2.983378	15.828154	0	0	0	0	21.686155	16.273258	22.616947
17	South	Rate M2	Commercial	23.247344	28.706057	29.672178	27.905081	32.821755	0	0	0	18.583902	31.830215	31.611649	28.724459
18	South	Rate M2	Industrial	41.190476	52.155539	49.895362	42.282259	56.828423	0	0	0	46.269006	58.340347	48.485736	51.373489
19	North	Rate 01	Residential	0.503893	0.455099	0.465464	0.452855	0.450826	0	0	0	0.156255	0.358193	0.466683	0.470843
20	North	Rate 01	Commerical	2.202577	1.780024	1.936525	1.735090	1.560934	0	0	0	0.584967	1.254686	1.722658	1.821911
21	North	Rate 10	Commercial	19.978605	23.052530	23.130268	22.938432	28.240337	0	0	0	11.648308	20.882752	23.592671	23.800732
22	North	Rate 10	Industrial	50.410898	84.517334	71.675583	39.310968	86.770595	0	0	0	67.456187	114.852436	101.064753	71.109097

Table 11
2025 Actual Weather Normalized Average Use by Region, Rate Class and Sector (m^3)
Normalized to 2025 Forecast Heating Degree Days (HDDs)

Line No.	Region	Rate Class	Sector	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	421	361	318	197	95	50	75	58	60	119	255	345	2,356
2	Central	Rate 6	Apartment	29,572	25,746	17,840	18,863	8,060	1,058	2,679	3,999	4,597	5,013	17,404	25,041	159,872
3	Central	Rate 6	Commercial	3,805	3,400	3,137	1,919	951	517	454	452	562	948	2,129	2,980	21,254
4	Central	Rate 6	Industrial	11,060	12,203	8,104	7,227	2,299	293	929	1,795	1,902	2,126	6,893	10,675	65,505
5	East	Rate 1	Residential	361	305	262	154	56	37	56	44	46	100	213	305	1,939
6	East	Rate 6	Apartment	13,496	11,906	8,779	7,888	3,378	(456)	456	1,589	1,437	2,082	8,457	11,589	70,600
7	East	Rate 6	Commercial	3,800	3,452	2,895	1,727	719	611	327	405	506	882	2,228	3,360	20,911
8	East	Rate 6	Industrial	27,866	25,305	16,404	22,435	1,665	(1,113)	1,260	4,409	5,277	5,959	17,424	29,521	156,413
9	West	Rate 1	Residential	354	309	272	182	74	38	58	47	45	87	210	281	1,957
10	West	Rate 6	Apartment	6,161	4,623	4,250	4,460	1,942	244	932	416	1,218	744	4,346	5,136	34,473
11	West	Rate 6	Commercial	3,036	2,824	2,732	1,790	827	451	375	509	538	879	1,791	2,581	18,334
12	West	Rate 6	Industrial	44,246	47,330	23,555	33,135	6,101	2,344	2,338	1,387	10,191	8,696	26,738	39,202	245,264
13	South	Rate M1	Residential	359	322	278	191	81	55	66	54	55	96	231	300	2,088
14	South	Rate M1	Commercial	1,497	1,120	1,195	798	256	129	210	154	197	383	1,051	1,200	8,190
15	South	Rate M1	Industrial	1,979	3,374	2,227	1,376	641	(205)	103	13	408	369	1,878	2,075	14,237
16	South	Rate M2	Residential	7,589	(3,923)	2,803	(2,095)	1,609	147	374	(1,637)	821	7,251	4,191	9,546	26,676
17	South	Rate M2	Commercial	15,572	16,226	13,786	11,327	6,049	3,072	4,219	3,088	4,932	9,526	15,874	17,623	121,293
18	South	Rate M2	Industrial	29,009	40,745	17,718	22,626	11,165	9,809	6,173	8,479	8,596	15,444	22,793	31,972	224,529
19	North	Rate 01	Residential	388	317	283	189	82	37	49	42	43	116	239	314	2,100
20	North	Rate 01	Commerical	1,755	1,126	1,260	831	295	129	192	171	174	464	997	1,338	8,732
21	North	Rate 10	Commercial	15,066	14,872	11,788	9,783	3,385	2,028	3,803	2,738	3,839	8,401	13,252	17,055	106,011
22	North	Rate 10	Industrial	34,731	63,368	18,687	21,044	28,947	13,790	8,139	(16,182)	58,398	31,789	39,049	37,907	339,667

Table 12
2025 Actual Weather Normalized Volumes by Region, Rate Class and Sector (10^3m^3)
Normalized to 2025 Forecast HDDs

Line No.	Region	Rate Class	Sector	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Central	Rate 1	Residential	684,019	586,215	517,601	320,764	155,310	81,745	122,778	94,913	97,790	194,686	416,210	563,325	3,835,354
2	Central	Rate 6	Apartment	166,784	145,076	100,526	106,291	45,443	5,965	15,124	22,565	25,933	28,310	98,299	141,409	901,727
3	Central	Rate 6	Commercial	486,833	435,257	401,291	245,313	121,161	65,705	57,739	57,494	71,497	121,274	273,821	384,253	2,721,639
4	Central	Rate 6	Industrial	56,825	62,613	41,576	37,037	11,758	1,492	4,722	9,121	9,679	10,859	35,400	54,817	335,898
5	East	Rate 1	Residential	136,284	115,256	99,461	58,271	21,434	14,077	21,228	16,879	17,495	38,083	81,546	116,939	736,954
6	East	Rate 6	Apartment	16,506	14,584	10,763	9,654	4,141	(561)	561	1,958	1,771	2,567	10,436	14,290	86,670
7	East	Rate 6	Commercial	84,273	76,631	64,241	38,279	15,902	13,503	7,206	8,921	11,167	19,515	49,481	74,764	463,884
8	East	Rate 6	Industrial	4,542	4,125	2,674	3,634	270	(180)	204	714	855	965	2,823	4,812	25,438
9	West	Rate 1	Residential	60,534	52,873	46,626	31,084	12,643	6,533	9,947	7,965	7,681	14,954	36,163	48,432	335,436
10	West	Rate 6	Apartment	2,871	2,159	1,989	2,092	909	114	436	195	571	348	2,034	2,414	16,132
11	West	Rate 6	Commercial	34,184	31,840	30,765	20,168	9,274	5,052	4,196	5,699	6,031	9,896	20,231	29,183	206,521
12	West	Rate 6	Industrial	11,991	12,779	6,360	8,880	1,635	628	627	372	2,731	2,322	7,193	10,545	66,062
13	South	Rate M1	Residential	403,273	360,939	312,934	214,512	90,814	61,608	74,557	61,394	61,974	108,768	260,582	339,306	2,350,661
14	South	Rate M1	Commercial	122,166	91,460	97,284	64,959	20,808	10,495	17,106	12,550	16,200	31,694	87,107	99,607	671,435
15	South	Rate M1	Industrial	7,329	12,468	8,137	5,024	2,330	(745)	374	46	1,512	1,386	7,096	7,880	52,838
16	South	Rate M2	Residential	1,374	(800)	538	(404)	311	21	39	(129)	66	363	184	410	1,972
17	South	Rate M2	Commercial	132,483	140,468	116,668	95,949	50,693	25,275	34,304	24,867	37,287	68,568	114,895	127,662	969,120
18	South	Rate M2	Industrial	40,526	58,021	24,469	31,224	15,095	13,360	8,408	11,480	11,063	18,749	28,173	39,517	300,084
19	North	Rate 01	Residential	133,075	108,568	97,093	64,736	28,156	12,639	16,800	14,533	14,946	40,027	82,393	108,290	721,256
20	North	Rate 01	Commerical	51,022	32,773	36,558	24,066	8,541	3,734	5,580	4,964	5,080	13,683	29,427	39,595	255,022
21	North	Rate 10	Commercial	38,931	39,023	30,273	25,043	8,548	5,140	9,333	6,657	8,464	17,406	27,605	35,287	251,710
22	North	Rate 10	Industrial	6,217	11,660	3,289	3,683	5,008	2,372	1,400	(2,735)	9,285	4,959	6,209	6,179	57,525
23	EGI			2,682,040	2,393,988	2,051,115	1,410,261	630,183	327,972	412,667	360,423	419,080	749,383	1,677,308	2,248,917	15,363,338

Table 13
2025 Actual Weather Normalized Volumes by Rate Class (10^3m^3)
Normalized to 2025 Forecast HDDs

Line No.	**Rate Class**	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	**Annual Total**
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	**(m)**
1	**Rate 1**	880,836	754,343	663,688	410,119	189,387	102,355	153,953	119,757	122,966	247,724	533,919	728,697	**4,907,744**
2	**Rate 6**	864,808	785,065	660,185	471,350	210,492	91,719	90,813	107,039	130,237	196,056	499,718	716,487	**4,823,971**
3	**Rate M1**	532,768	464,867	418,354	284,495	113,953	71,357	92,037	73,989	79,686	141,849	354,785	446,792	**3,074,933**
4	**Rate M2**	174,382	197,689	141,675	126,769	66,098	38,655	42,751	36,218	48,417	87,679	143,252	167,590	**1,271,176**
5	**Rate 01**	184,096	141,341	133,651	88,802	36,698	16,373	22,380	19,497	20,026	53,710	111,820	147,885	**976,278**
6	**Rate 10**	45,148	50,683	33,562	28,726	13,555	7,512	10,733	3,922	17,749	22,365	33,813	41,466	**309,235**
7	**EGI**	2,682,040	2,393,988	2,051,115	1,410,261	630,183	327,972	412,667	360,423	419,080	749,383	1,677,308	2,248,917	**15,363,338**

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedules 2-3

Question(s):

Please explain the drivers of the revenue increase for rate 332.

Response:

The increase for Rate 332 is primarily driven by a higher OEB approved rate[1].

[1] EB-2024-0111, Interim Rate Order, November 29, 2024, Appendix A.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedules 2-3

Question(s):

Please provide an explanation of all categories included in line 8 Other Operating Revenue.

a) Using those categories, please explain the reduction in revenue for this line item.

Response:

Other operating revenue primarily includes Demand Side Management Incentive, third-party maintenance revenue, affiliate lease revenue, and other miscellaneous adjustments. Line 8 of Other Operating includes the Demand Side Management Incentive that is removed in Line 10 as a utility adjustment.

a) Lower Demand Side Management Incentive revenue accounted for $1.6 million of the year-over-year decrease. The remaining $3.9 million decrease primarily reflected a $2.0 million reconciliation and cleanup of 2024 bank and accounts payable balances, with the balance attributable to lower third-party maintenance revenue, affiliate lease revenue, and other miscellaneous adjustments.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Schedules 2-3

Question(s):

Please provide specifics on adjustment in line 13 and the specific drivers for the $8.8M and its variance from 2024.

Response:

The adjustment on line 13, Column (b) of $8.8 million is primarily related to the $8.5 million shareholder portion of the gain on sale of land disposed of in 2025 and reflected in the year end Corporate results as reflected in Exhibit B, Tab 1, Schedule 3, line 5, column (a). As 50% of the gain on the sale of land is shared with ratepayers and reflected in the Disposition of Property Deferral Account, this $8.5 million is the shareholder portion that remains in Enbridge Gas's results which are removed from the determination of utility results. The variance of this line item as compared to 2024 results from no property dispositions occurring in 2024, and therefore there was no required utility adjustment in the prior year.

The remaining $0.3 million pertains to non-utility interest income that are removed from utility results, which is lower than the $0.6 million in 2024.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 1

Preamble:

Table 1, Line 4 shows an increase of $17M in Professional and Regulatory Services. We would like to understand this increase better.

Question(s):

For each of the outside organizations who provided these services, please provide:

a) The scope of work

b) The RFP used to engage these services

c) The initial agreement for the work to be undertaken including the pricing

d) The change orders approved to any scope changes

e) The invoicing by the provider

Response:

a-e) Exhibit B, Tab 3, Schedule 1, Table 1, line 4 shows a $17.0 million increase in Professional and Regulatory Services. As explained in Exhibit I.CCC-3, this amount includes $10 million in affiliate consulting costs paid by Enbridge Gas Inc. on behalf of Enbridge affiliates and recovered through line 11, Internal Allocations and Recoveries. Excluding these flow-through costs, the remaining change reflects a $10 million increase in consulting costs, partially offset by approximately $3.0 million in reduced net OEB assessment costs in 2025 versus 2024.

Nearly all of the $10 million increase in 2025 consulting costs are related to services provided by McKinsey & Company Canada (McKinsey) for Enbridge Gas and the former Dominion Energy gas distributors in Ohio, North Carolina and Utah (now collectively referred to as the Enbridge Gas Distribution & Storage, or GDS,

business segment). The work was aimed at finding sustainable operational efficiencies across these utilities, both collectively and individually.

The costs associated with this work were allocated 50% to Enbridge Gas Inc. and 50% to the other gas utilities in the GDS segment, based on each utility's proportionate share of total customer count.

As a result of the work completed by McKinsey in 2025, Enbridge Gas will be able to realize approximately $6.5 million in total sustainable annual O&M savings opportunities in future years:

- Supply Chain Management: Estimated annual savings of $1.0 million through direct supplier negotiations, beginning in 2026 and continuing annually thereafter.
- Engineering Standards: Estimated annual savings of $1.1 million through efficiencies in valve inspections, odorant checks, and station equipment inspections. Savings are expected to be $0.4 million in 2026, increase to $1.1 million in 2027, and continue annually thereafter.
- Work Management: Estimated annual savings of $4.4 million through reduced overtime, lower contractor expenditures, and workforce attrition. Savings are expected to be $2.2 million in 2026, increase to $4.4 million in 2027, and continue annually thereafter.

McKinsey was engaged by Enbridge Inc., Enbridge Gas Inc.'s parent company, to provide services across the enterprise. Enbridge Inc. negotiated and administered the RFP and master agreement in 2017, and these documents are not specific to Enbridge Gas Inc. As such, these are not relevant to the review of the Enbridge Gas 2025 ESM determination.

At Attachment 1, Enbridge Gas has provided the relevant documents setting out the scope of work undertaken by McKinsey for the GDS business segment, in respect of which Enbridge Gas has included costs in its 2025 results. Table 1 summarizes the McKinsey work completed in 2025 that underpins the $10 million increase in Professional and Regulatory Services.

Table 1
McKinsey Work Description

Line No.	Work Engagement Title	Work Description
1	GDS Full Potential	The Full Potential work focused on assessing GDS's current state, identifying similarities and differences across the LDCs, and highlighting potential cost-saving opportunities for further evaluation.
2	GDS Supply Chain Management (SCM)	The work with GDS SCM was in a consulting capacity, providing recommendations, guidance, and subject-matter input focused on a detailed assessment of opportunities to optimize third-party spend and enhance supply chain performance.
3	GDS Strategy Workshop	The work with the GDS Vision and Prioritization engagement was in a consulting capacity, providing recommendations, guidance, and subject-matter input focused on identifying key business opportunities and challenges, as well as supporting management in evaluating potential initiatives.
4	GDS Engineering Standards	The work with GDS Engineering Standards engagement was a consulting capacity, providing recommendations, guidance, and subject-matter input focused on evaluating opportunities to enhance the efficiency and effectiveness of maintenance operations through selected standard operating procedures (SOPs) and engineering standards.
5	GDS Work Management - Regional Deep Dive	The GDS Work Management Regional Deep Dive engagements focused on assessing and enhancing GDS planning and scheduling processes. The scope included developing and piloting an improved planning and scheduling model, enhancing performance metrics, and supporting implementation.
6	GDS Strategy Workshop	The work with the GDS 2025 Fall Strategy Session was in a consulting capacity, providing recommendations, guidance, and subject-matter input focused on supporting leadership in consolidating, refining, and evaluating its proposed goals and priorities for 2026.

GDS Full Potential

STATEMENT OF WORK

FOR

CONSULTING SERVICES

BETWEEN

ENBRIDGE EMPLOYEE SERVICES CANADA INC.

AND

MCKINSEY & COMPANY CANADA

SOW Number: McKinsey-CN-3300-GDS-Full_Potential-SOW32

Services Name: GDS Full Potential

SOW Effective Date: February 25, 2025

ATTACHMENT 2.2

GDS Full Potential Services

1. GDS Full Potential Services

Supplier will perform the following Services/Activities as part of this SOW:

(a) Build the financial baseline of each OpCo to understand today's performance and growth based on business-as-usual growth. Key activities include:

(i) Gather and incorporate existing efforts to understand current state view of growth opportunities, OpCo performance, existing financial model, etc.

(ii) Refine view of current performance across key cooperate metrics (e.g., earned vs allowed ROE, EBITDA, DCF)

(iii) Create a baseline momentum case and determine gap to meet or exceed annual growth targets at each OpCo

(iv) Assess growth "profile" for each OpCo and relative trajectory given customer growth, rate structure and estimated affordability headroom; testing against growth ambition

(v) Assess current gap and potential for additional capital deployment

(b) Estimate the full potential by evaluating the opportunity within operations, capital and corporate functions across GDS and for each OpCo, building on work recently completed

(i) Conduct interviews and benchmarks (both between OpCos and with peers) to identify areas of opportunity for both gas and customer operations and capital

(ii) Benchmark central function costs (incl. direct and allocated) to identify areas of opportunity

(iii) Identify areas of the business with the highest value potential based on risk vs. reward framework (e.g., EBITDA impact, policy/regulatory risk)

(iv) Conduct additional deep dives on short-listed areas to further validate areas of opportunity and structure initiatives for each OpCo and GDS overall, as needed

(c) Develop a draft, sequenced roadmap for each OpCo and GDS overall into a timeline that maximizes earnings

(i) Prioritize focus areas against the potential value unlocked, risk, and ease of implementation; along with other considerations (e.g., timing of rate case outcomes)

(ii) Based on prioritization, create draft timeline and sequencing of initiatives with required resourcing, for each OpCo and GDS overall

ATTACHMENT 2.3
GDS Full Potential Deliverables

For the purposes of this Scope of Work, the following list sets out the applicable Deliverables, including, for each, the Specifications, Deadline, and the type of Deliverable (Documentation Deliverable or regular).

Deliverable	Deadline	Deliverable Type
Financial baseline of each OpCo to understand performance today and base outlook (e.g., earned vs. allowed ROE, EBITDA, DCF)	May 2, 2025	Financial model
Growth trajectory for each OpCo, based on business-as-usual growth and affordability headroom	May 2, 2025	Financial model
The full value potential across GDS, with an initial breakdown of opportunity sizing by area, function, etc. for each OpCo and GDS overall	May 2, 2025	Document
'Big Rocks' summary of priority opportunities for each OpCo, including value at stake for each	May 2, 2025	Document

Prioritized set of initiatives with a draft roadmap to help plan for initiative design and implementation for each OpCo and GDS overall	May 2, 2025	Document

ATTACHMENT 2.4
Workplan for GDS Full Potential

Exhibit 1: GDS Full Potential Workplan

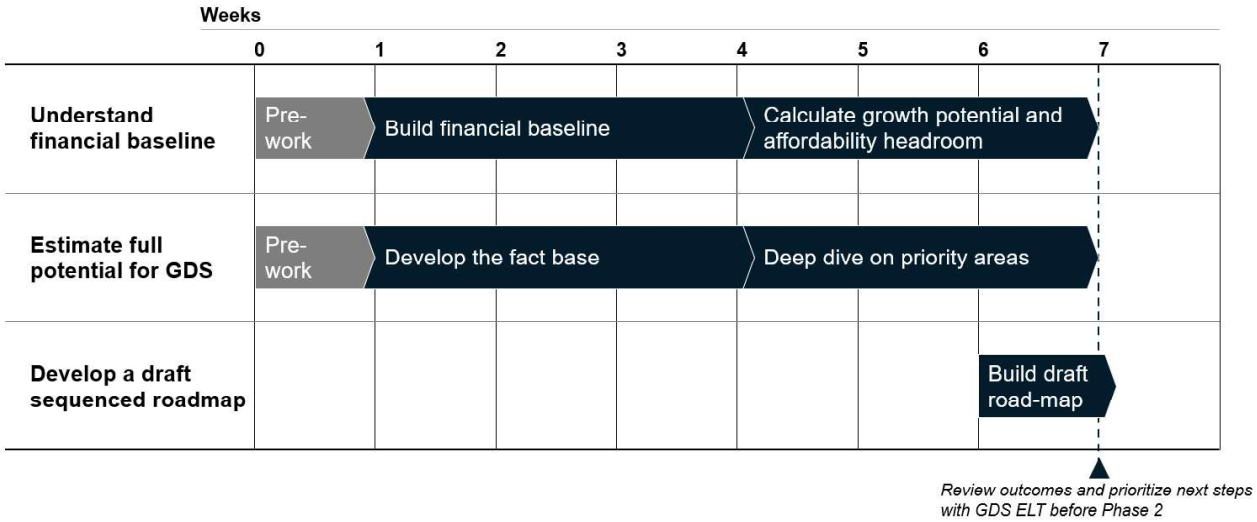


Exhibit 2: Approach for financial baseline

We will co-develop the financial baseline with GDS / OpCo finance teams, building on work already done. We will use this to assess the growth profile at each OpCo

	3 weeks	3 weeks
	Build financial baseline	**Calculate growth profile and affordability headroom**
Activities	• **Gather and incorporate existing efforts to** understand current state view of growth opportunities, OpCo performance, existing financial model, etc. *(pre-work)* • **Refine view of current performance** across key cooperate metrics (e.g., earned vs allowed ROE, EBITDA, DCF) • **Create a baseline momentum case** (i.e., impact of ongoing initiatives) **and determine gap** to meet or exceed annual growth targets at each OpCo (e.g., $150 M EBITDA)	• **Assess growth "profile" for each OpCo** (and relative trajectory) given customer growth, rate structure and estimated affordability headroom; testing against growth ambition • **Gap assessment** and potential for additional capital deployment

Exhibit 3: Approach for full potential estimation

We will deep dive into operations corporate functions to identify opportunity areas and start building a picture of the full value potential

	3 weeks	3 weeks
	Develop the fact base	**Deep dive on priority areas**
Activities	*Refresh and build on diagnostic work completed recently (e.g., N75/WBT, Integration, Surge)* • **Conduct interviews and benchmarks** (both between OpCos and with peers) to identify areas of opportunity for both gas and customer operations and capital • **Benchmark central function costs (incl. direct and allocated)** to identify areas of opportunity	• **Identify areas of the business with the highest value potential** based on risk vs. reward framework (e.g., EBITDA impact, policy/regulatory risk) • **Conduct additional deep dives on short-listed areas** to further validate areas of opportunity and structure initiatives for each OpCo and GDS overall, as needed

Exhibit 4: Approach for draft sequenced roadmap

We will prioritize the full potential output to develop a draft sequenced roadmap for each OpCo and GDS overall

	1 week
	Prioritize opportunities and build draft roadmap
Activities	• **Prioritize focus areas** against the potential value unlocked, risk, and ease of implementation; along with other considerations – e.g., timing of rate case outcomes, "racking and stacking" of benefit by OpCo • Based on prioritization, **create draft timeline and sequencing of initiatives with required resourcing**, for each OpCo and GDS overall

GDS Supply Chain

STATEMENT OF WORK

FOR

CONSULTING SERVICES

BETWEEN

ENBRIDGE EMPLOYEE SERVICES CANADA INC.

AND

MCKINSEY & COMPANY CANADA

SOW Number: McKinsey-CN-3300-GDS-Supply_Chain-SOW33

Services Name: GDS Supply Chain

SOW Effective Date: February 26, 2025

ATTACHMENT 2.2

GDS Supply Chain Services

1. **GDS Supply Chain Services**

Supplier will perform the following Services/Activities as part of this SOW:

(a) Set the aspiration and baseline:

(i) Gather existing spend by category for all four OpCos, as well as ongoing SCM efforts (prior to kick off)

(ii) Define baseline for GDS third party spend

(iii) Align on total cost of ownership (TCO) savings potential based on benchmarks, ENB and McKinsey expertise

(iv) Run dip-stick analyses and interviews to validate TCO opportunity

(v) Host workshop to prioritize categories and levers for execution

(b) Capture value through the first wave of sourcing, across all levers of TCO:

(i) Demand and spec levers (examples):

A. Optimizing in/outsourcing of field and call center work, move to self-service where possible

B. Demand controls across indirect spend and contractors

C. Contractor management to reduce OT and sources of waste in scopes

D. Crew mix optimization, e.g., optimized journeyman-to-helper ratios

(ii) Commercial and pricing levers (examples):

A. Cleansheet-based, highly competitive sourcing events (RFP preparation, analytics, negotiation support, and award scenarios)

B. Optimized commercial contract structures

ATTACHMENT 2.3
GDS Supply Chain Deliverables

For the purposes of this Scope of Work, the following list sets out the applicable Deliverables, including, for each, the Specifications, Deadline, and the type of Deliverable (Documentation Deliverable or regular).

The below tables assumed the 1-week workshop is on Mar 10-14, 2025 and that the first 16-week value capture wave launches Mar 24, 2025 and concludes Jul 11, 2025. Please consider this a DRAFT set of dates, to be refined with Project Lead.

Deliverable	Deadline	Deliverable Type
1-week diagnostic: Aligned baseline	Mar 14, 2025 – end of workshop week	Model with category baselines
1-week diagnostic: Prioritized categories & levers for execution	Mar 14, 2025 – end of workshop week	Model with categories sequenced in waves
1-week diagnostic: Preliminary opportunity ramp-up	Mar 14, 2025 – end of workshop week	Top-down model showing value opportunity across waves
Implementation: Bottom line impact in Wave 1 categories, across relevant TCO levers	Jul 11, 2025	New pricing agreement / demand or spec changes in place
Implementation: Lined-up set of categories for next waves	Jul 11, 2025	Model with categories sequenced in waves
Implementation: Upgraded category management practices based on new levers	Jul 11, 2025	Document

ATTACHMENT 2.4
Workplan for GDS Supply Chain

Exhibit 1: GDS Supply Chain Workplan

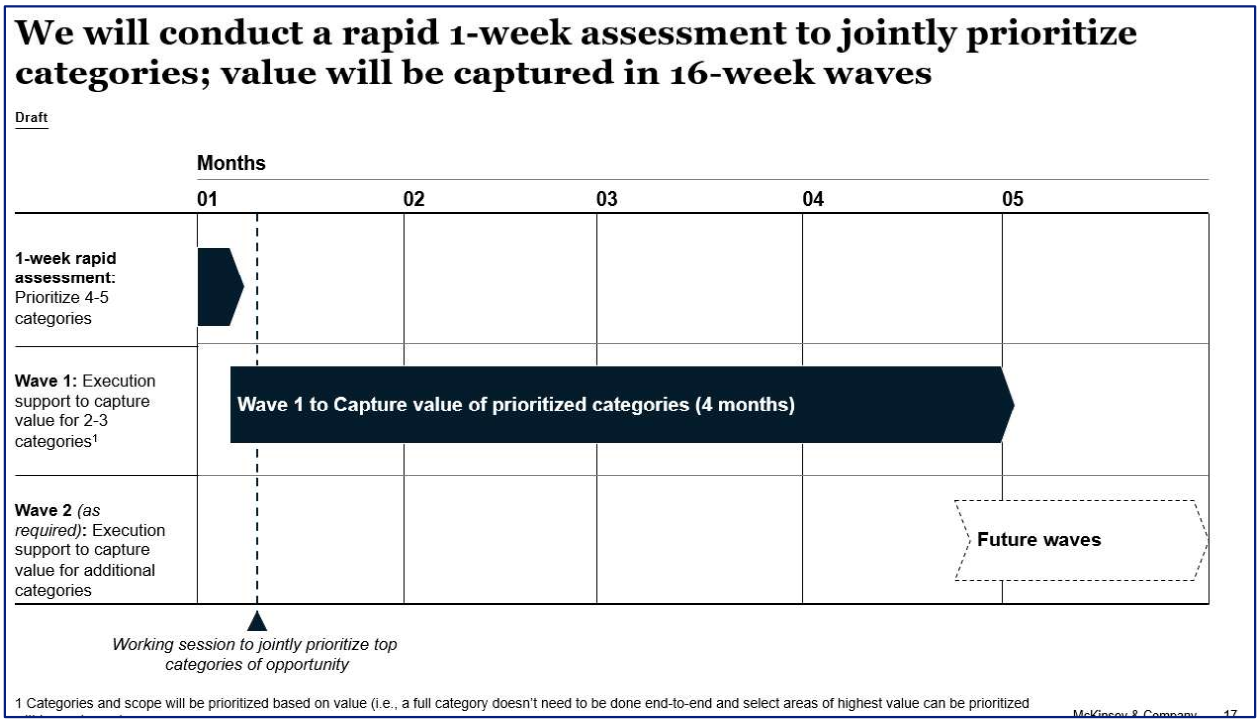
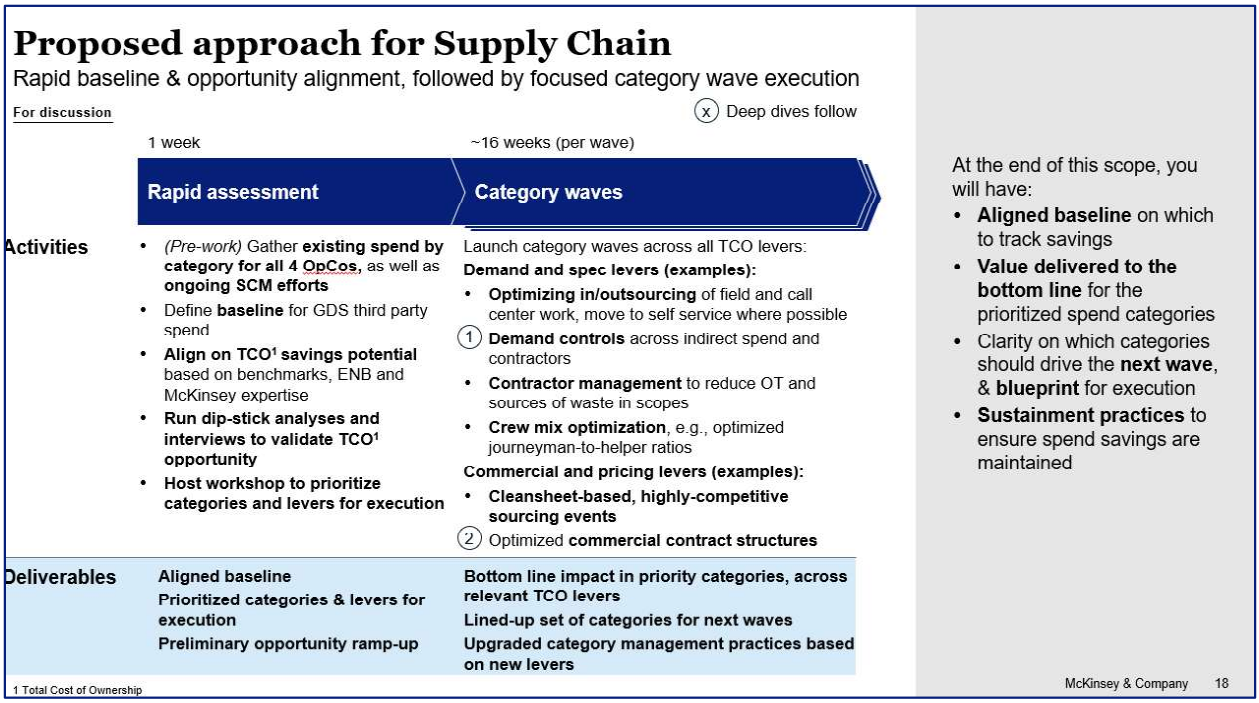


Exhibit 2: Activities and deliverables



GDS Vision and Prioritization

STATEMENT OF WORK

FOR

CONSULTING SERVICES

BETWEEN

ENBRIDGE EMPLOYEE SERVICES CANADA INC.

AND

MCKINSEY & COMPANY CANADA

SOW Number: McKinsey-CN-3300-GDS_Vision-SOW34_Final

Services Name: GDS vision and prioritization

SOW Effective Date: March 13th, 2025

ATTACHMENT 2.2

GDS Vision and Prioritization Services

1. **GDS Vision and Prioritization Services**

Supplier will perform the following Services/Activities as part of this SOW:

(a) Prepare for a GDS leadership workshop in early May 2025 with key activities including:

(i) Running an executive workshop with all VPs and above

(ii) Build a perspective on ways in which other companies have driven and shaped the industry they are in

(iii) Work with Enbridge leads to gather opportunities for discussion at the workshop

(iv) Develop a detailed workshop facilitation and logistics plan to run the workshop

(b) Lead and facilitate a workshop in early May that supports the GDS leadership team to:

(i) Strive towards driving, shaping and growing using external examples for inspiration

(ii) Lay out the case for change for GDS using current momentum case financials

(iii) Summarize and refine top initiatives for 2025/6 with challenge sessions to push for greater aspiration, acceleration and scale across GDS

(iv) Prioritize the initiatives that GDS wants to put resources to over the next 2-3 years

ATTACHMENT 2.3
GDS Vision and Prioritization Deliverables

For the purposes of this Scope of Work, the following list sets out the applicable Deliverables, including, for each, the Specifications, Deadline, and the type of Deliverable (Documentation Deliverable or regular).

Deliverable	Deadline	Deliverable Type
Facilitated workshop over 1-1.5 days in ON with GDS executive team (draft agenda below)	May 1 2025	Workshop

Proposed agenda

McKinsey led ENB led

Could be pushed to an afternoon session the day before

DRAFT – FOR DISCUSSION

Agenda item	Proposed format	Duration	Time
Opening remarks from Michele and workshop kick -off		15 min	8:00-8:15 PM
Where we are today (Enbridge) • Provide an overview of momentum case for each OpCo, including current ROE performance and drivers of performance, along with a view of potential forward projections for - new customer connections, margins, new products and services • Regulatory strategy to unlock opportunities.	Presentation	45 min	8:15- 9:00 AM
What others are doing Discussion and exercise with some case examples of what others are doing to drive and shape the industry they are in: • Highlight examples of what other utilities are doing to drive growth • 1-2 case examples outside of utilities e.g. Tesla giga factory	Facilitated discussion	60 min	9:00-10:00 AM
Break		15 min	
Enbridge 2025 opportunities • Each GDS business lead[1] talks about their top 3 concrete initiatives for 2025/26 highlighting: goal of the initiative, EBITDA benefit, regulatory unlocks required, support needed, options to accelerate (10 min per presentation). Business leads will be prepped to highlight where GDS is being growth oriented/market shaping, how the initiative creates impact across Enbridge	Plenary discussion	75 min	10:15-11:30 AM
Lunch		45 min	11:30-12:15 PM
Opportunity challenge sessions - are we growing & innovating and leading the way? • Breakouts by business area where pressure test the 3 opportunities . Goals of the session will be to challenge - is it ambitious enough, can it be scaled across Enbridge, is it feasible, how can we accelerate? What regulatory outcomes do we need and how do we shape this? (30 min per opportunity)	Break outs	105 min	12:15-2:00 PM
Break		15 min	
Prioritization of opportunities (preliminary) • The opportunities across regions and central functions are gathered and prioritized (high level) based on: EBITDA contributio n to target, feasibility, resource availability	Plenary	60 min	2:15-3:15 PM
Opportunity commitment and report out • Synthesis of prioritized opportunities, e ach business lead highlights the 4-5 actions committed to, in order to accelerate/act	Plenary	30 min	3:15-3:45 PM
Wrap up and close by Michele		15 min	3:45-4:00 PM

ENBRIDGE

1. Regionalleads, Steve, Jim, Lasdo

3

Gas Distribution & Storage (GDS) Specs & Standards

STATEMENT OF WORK

FOR

CONSULTING SERVICES

BETWEEN

ENBRIDGE EMPLOYEE SERVICES CANADA INC.

AND

MCKINSEY & COMPANY CANADA

SOW Number: McKinsey-CN-3300-GDS_Specs-SOW35

Services Name: GDS Specs & Standards

SOW Effective Date: July 3, 2025

ATTACHMENT 2.2

GDS Specs & Standards Services

1. GDS Specs & Standards Services

Supplier will perform the following Services/Activities as part of this SOW:

(a) Build baseline of Enbridge's GDS standard operating procedures, and engineering standards that govern operations ("SOPs") to understand current state and support the prioritization of the current SOPs for deep dive revision. Key activities will include:

(i) Build baseline of SOP utilization, performance, complexity and spend

(ii) Recommend top ~7–10 SOPs for deep-dive revision; Enbridge to confirm final priorities

(iii) Develop high level (+/- 50%) estimates of the value at stake for these SOPs (hours, spend, saved by optimizing SOPs)

(iv) Prepare approach utilizing kaizen type / CI process, focusing on quick wins and optimizing SOPs (not full redesign) necessary to capture the value at stake

(v) Nominate key Enbridge subject matter expert (SME) personnel from engineering, operations / maintenance and regulatory to sprint team. Note - Supplier will rely on Enbridge to provide the appropriate SME personnel relevant to the prioritized SOPs

(b) Conduct three ~2 week sprints to optimize 7 priority SOP categories, using workshops/working sessions (simplified kaizen type approach, where Supplier goes from leading to teaching). Key activities include:

(i) Understand scope and steps involved in Enbridge's GDS SOPs and historical performance, e.g., effectiveness of work, duration vs. standard, discovery work

(ii) Map steps, information flow and resources, and working with SMEs, develop initial hypothesis of optimization of safety, risk/reliability, and cost/hours

(iii) Conduct simplified-Kaizen-type workshop to optimize SOPs through minimum technical solution (MTS), lean/waste elimination

(iv) Synthesize and align on changes with Enbridge SMEs, including engineering, for each SOP and next steps to revise content / process to validate changes

(v) Develop change management approach and communications plan

(c) Build out “Enbridge Specs and Standards Playbook” concurrently with second two sprints to allow GDS to replicate the process for more SOPs

(d) Conduct an SOP prioritization deep dive through workshops/working sessions, working with Enbridge GDS operations and engineering to clean up overall SOPs list to support Enbridge in quickly eliminating repetitive, unnecessary or un-needed SOPs

Enbridge acknowledges that Supplier is not an expert with respect to health, safety, quality, legal, and regulatory standards and requirements that may apply to Enbridge’s operations (collectively, “Standards and Requirements”) and Enbridge must rely on its own expertise and the expertise of its specialist legal, operations, safety, and other advisors, including to conduct investigation, due diligence and risk assessment in their areas of expertise and determine whether to pursue the recommendations provided under this SOW. Supplier does not supplant Enbridge’s management or other decision-making bodies. Enbridge remains solely responsible for its decisions (including decisions about how to operate its process), actions, use of the Deliverables, implementation of Supplier’s advice and recommendations and its compliance with applicable laws, rules, regulations, Standards and Requirements. Enbridge agrees that Supplier will not be responsible to any party, including any government agency, for Enbridge’s failure to comply with applicable Standards and Requirements and Enbridge retains sole responsibility for the quality and safety of its processes and operations.

ATTACHMENT 2.3
GDS Specs & Standards Deliverables

For the purposes of this Scope of Work, the following table sets out the applicable Deliverables, including, for each, the Deadline, and the type of Deliverable . All dates assume a July 7th start date.

Deliverable	Deadline	Deliverable Type
Prioritization of top ~7-10 SOPs, with high level (+/-50%) estimate of value at stake	September 15, 2025	Documentation
Optimized processes and requirements tied to prioritized SOPs reviewed in sprints with decisions on changes made and plan to implement developed	September 15, 2025	Documentation
List of redundant SOPs that can be eliminated	September 15, 2025	Documentation

ATTACHMENT 2.4
Workplan for GDS Specs & Standards

Exhibit 1: GDS Specs & Standards 8-week workplan

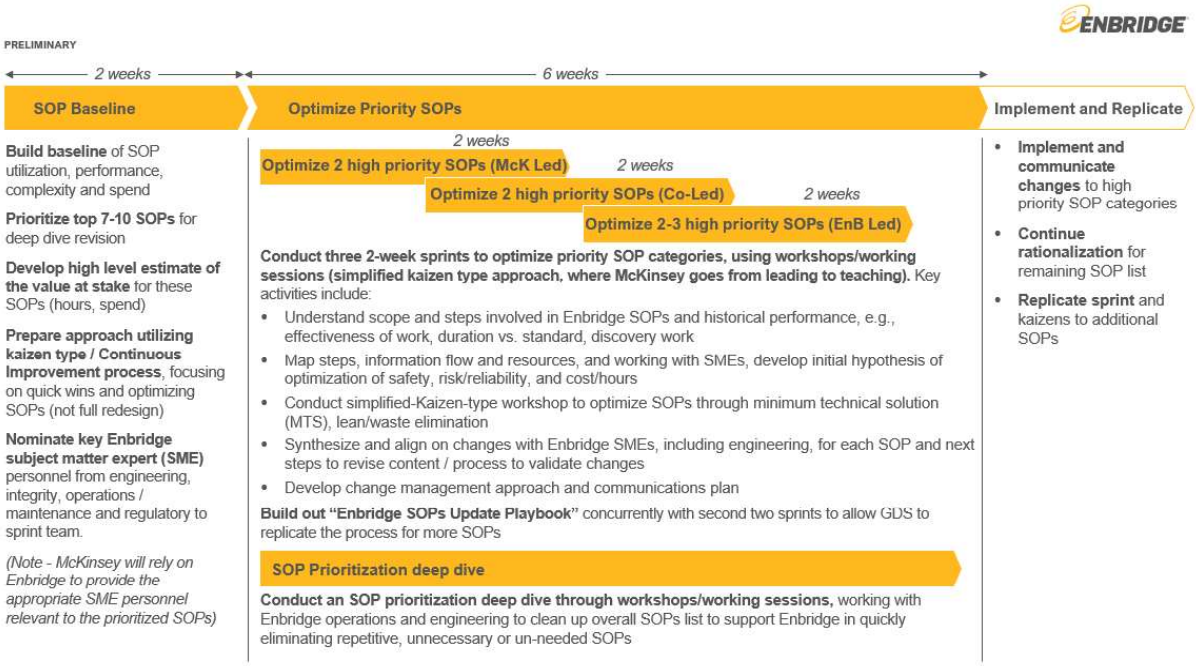
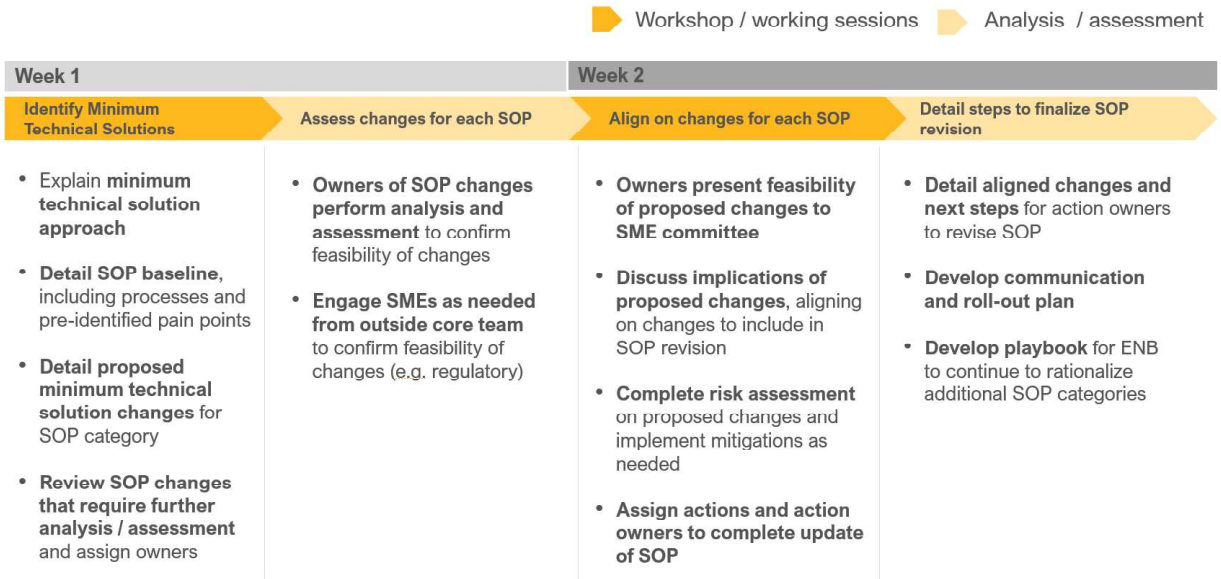


Exhibit 2: GDS Specs & Standards: Example key activities of 2-week sprint



Gas Distribution & Storage (GDS) Planning & Scheduling

STATEMENT OF WORK

FOR

CONSULTING SERVICES

BETWEEN

ENBRIDGE EMPLOYEE SERVICES CANADA INC.

AND

MCKINSEY & COMPANY CANADA

SOW Number: McKinsey-CN-3300-GDS_Planning-SOW36

Services Name: GDS Planning & Scheduling

SOW Effective Date: July 3, 2025

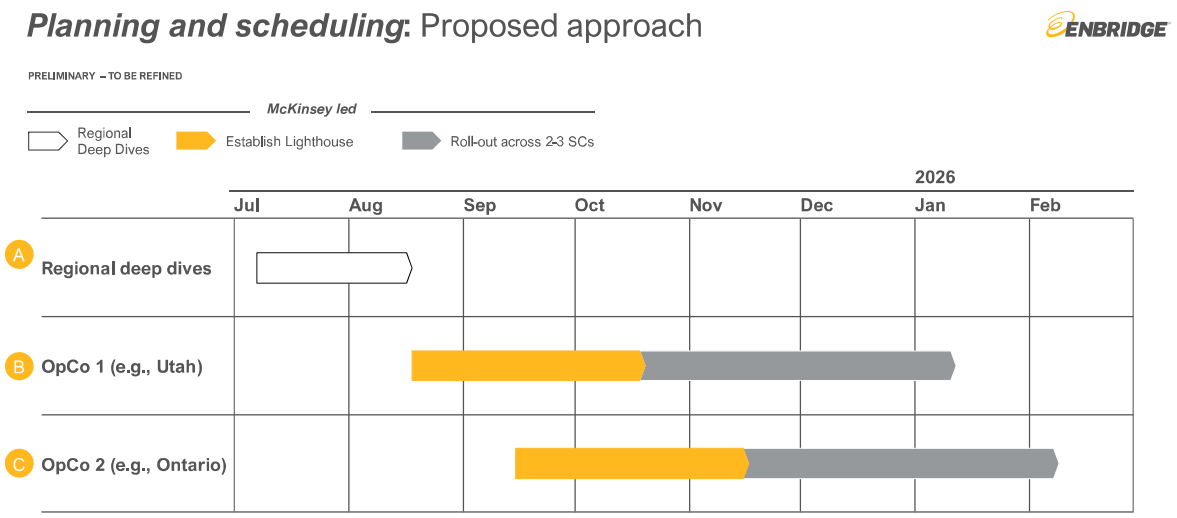
ATTACHMENT 2.2

GDS Planning & Scheduling (P&S) Services

1. GDS Planning & Scheduling Services

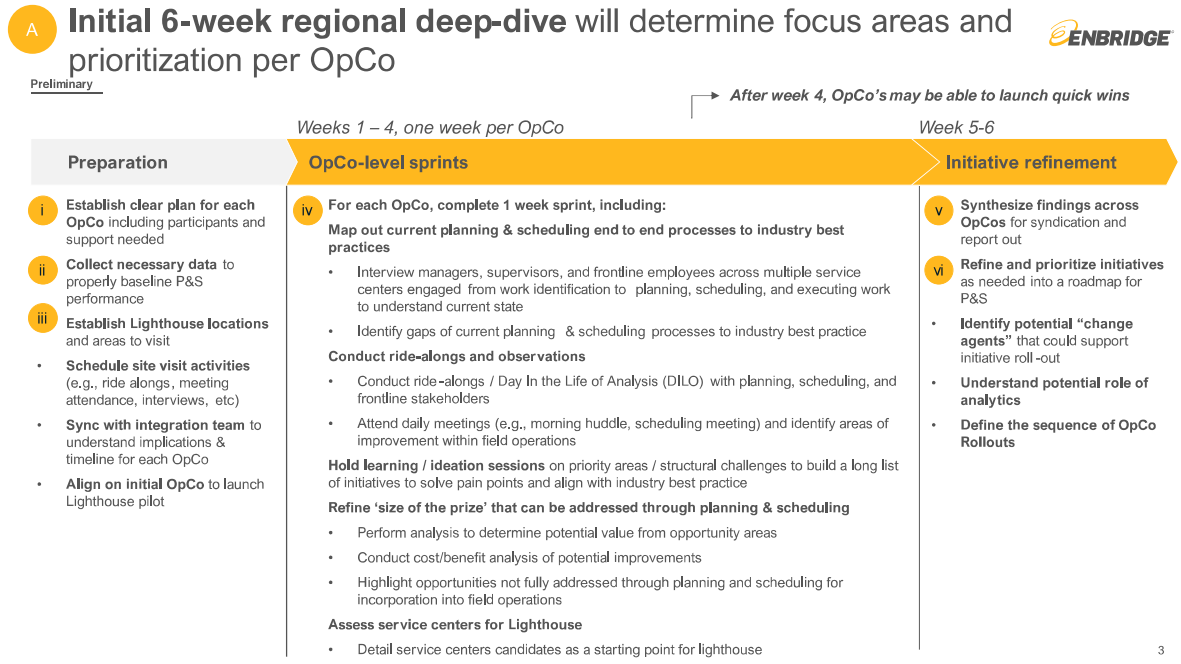
Supplier will perform the following Services/Activities as part of this SOW as outlined in Exhibit 1 and detailed below. The work will focus on assessing current planning & scheduling process across all 4 Operating Companies ("OpCos"): Ontario, North Carolina, Utah, and Ohio, during the "Regional Deep Dives" phase. Additionally, this SOW will cover the rollout of a new planning & scheduling process at 2 OpCos, to be jointly decided on during the "Regional Deep Dives" phase.

Exhibit 1: Planning and scheduling proposed approach



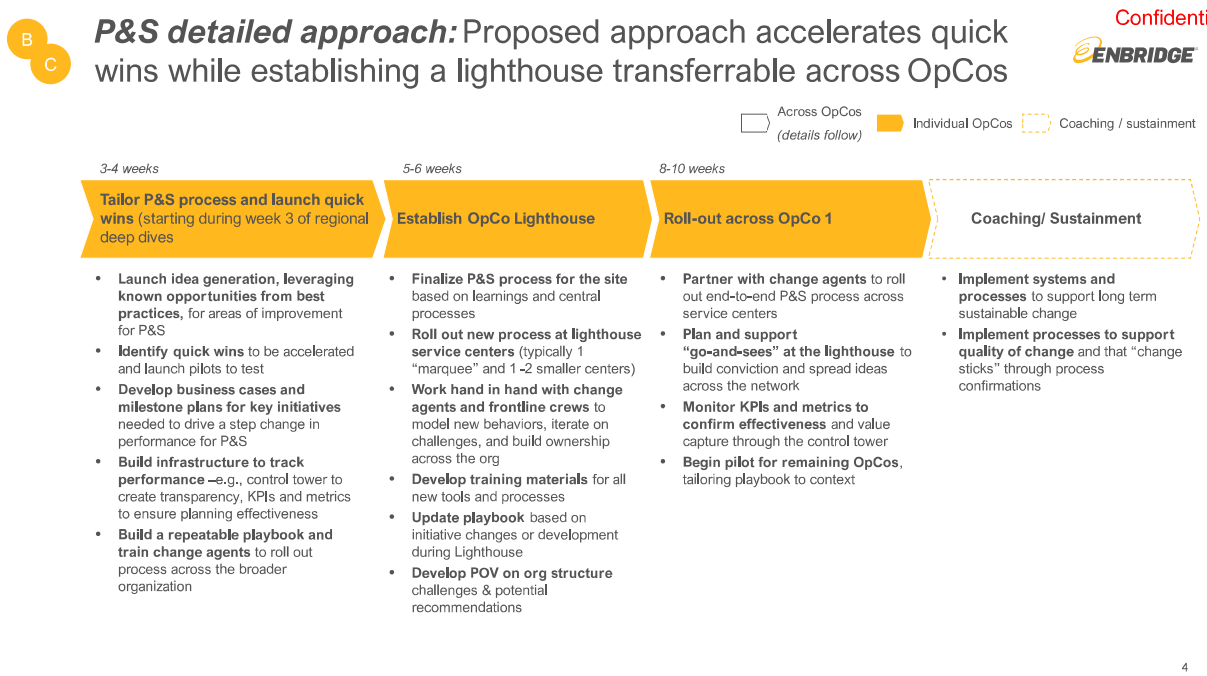
A. Phase 1 - Regional Deep Dives: Supplier will perform the following Services / Activities, as outlined in Exhibit 2:

Exhibit 2: Regional Deep Dive Activities & Deliverables



B & C. Phase 2 - OpCos 1 (e.g., Utah) & 2 (e.g,, Ontario) Supplier will perform the following Services / Activities in OpCos 1 and 2 (to be jointly determined during Regional Deep Dive Phase), as outlined in Exhibit 3:

Exhibit 3: OpCo 1 Rollout Plan



ATTACHMENT 2.3
GDS Planning & Scheduling Deliverables

For the purposes of this Scope of Work, the following list sets out the applicable Deliverables as identified in the table below. All dates assume a July 7th start date.

Deliverable	Deadline	Deliverable Type
OpCo deep-dives, evaluating current process against best practices, with refined value at stake	August 15th, 2025	Document
Prioritization of OpCos and Monetization Strategy	August 29st, 2025	Document

Monitoring dashboard of KPIs / metrics to track progress for use in “control tower” and the Steering Committee for both OpCos 1 and 2	September 26th, 2025	Dashboard
Tailored planning & scheduling playbook, with quantified areas of improvement (initiatives) and quick wins	December 12th 2025	Document
Established OpCo lighthouse at 1 – 2 service centers in OpCos 1 & 2	November 28th, 2025	Functioning pilot / proof of concept at single location
Functioning planning and scheduling process rolled out at remaining service centers in OpCos 1 and 2	February 29th 2026	Written confirmation of adoption

GDS 2025 Fall Strategy Session

STATEMENT OF WORK

FOR

CONSULTING SERVICES

BETWEEN

ENBRIDGE EMPLOYEE SERVICES CANADA INC.

AND

MCKINSEY & COMPANY CANADA

SOW Number: McKinsey-CN-3300-GDS_2025-Strategy-SOW37

Services Name: GDS 2025 Fall Strategy Session

SOW Effective Date: August 1st, 2025

ATTACHMENT 2.2

GDS 2025 Fall Strategy Session Services

1. **GDS 2025 Fall Strategy Session Services**

Supplier will perform the following Services/Activities as part of this SOW:

(a) Prepare for a GDS leadership workshop in early October 2025 with key activities including:

(i) Running an executive workshop with all VPs and above

(ii) Bring external perspectives on customer focus and effectively delivering products and services

(iii) Work with Enbridge leads to gather, consolidate and refine their goals for 2026

(iv) Develop a detailed workshop facilitation and logistics plan to run the workshop

(b) Lead and facilitate a workshop in early October that supports the GDS leadership team to:

(i) Provide updates on current business and key priority areas

(ii) Showcase internal GDS examples of customer focus and effectively delivering products and services

(iii) Consolidate and refine 2026 goals and priorities

(iv) Facilitate interactive sessions to consolidate and pressure test 2026 plan

ATTACHMENT 2.3
GDS 2025 Fall Strategy Session Deliverables

For the purposes of this Scope of Work, the following list sets out the applicable Deliverables, including, for each, the Specifications, Deadline, and the type of Deliverable (Documentation Deliverable or regular).

Deliverable	Deadline	Deliverable Type
Facilitated workshop over 1 days in Houston with GDS executive team (draft agenda below)	Oct 8 2025	Workshop

October 8th agenda

DRAFT – FOR DISCUSSION

Agenda item	Proposed format and lead	Duration	Time
Opening remarks from Michele, safety moment and workshop kick-off	Michele	10 min	8:00- 8:15 AM
Where we are today: Update on growth strategy and initiatives from April workshop, regulatory update OH rate case, other relevant updates	Presentation: Heidi/Steve, Laszlo/Rusty	60 min	8:15-9:15 AM
Focus on customer:			9:15-10:15 AM
GDS recap of Customer focus led by Teresa	Teresa	20 min	
External example on deep Customer orientation	McKinsey/external speaker	20 min	
Facilitated discussion on what more we can be doing on Customer	Facilitated discussion	20 min	
Break		30 min	10:30-11:00 AM
Effectively delivery services:			11:00 AM-12:00 PM
GDS recap of full potential	Jen	20 min	
External example on Effectively delivering services (e.g. leveraging AI for workforce/route optimization)	McKinsey/external speaker	20 min	
Facilitated discussion on what more we can be doing on Delivery of services	Facilitated discussion	20 min	
Lunch		60 min	12:00-12:45 PM
2026 GDS goals: presentation of 2026 goals by pillar within the region and key shared services	Judd, Rusty, Brian, Brady with support from Laszlo, Steve, Jim (20 min each)	~120 min	12:45-2:45 PM
Break		15 min	2:45-3:00 PM
Discussion/breakouts/gallery walk: group discussion on 2026 goals to identify gaps, interdependencies and shared services needs	TBD	45 min	3:00-3:45 PM
Wrap up and close by Michele	Michele	15 min	3:45-4:00 PM

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 2

Preamble:

We would like to understand better the major drivers of the variances provided in Table 2

EGI evidence states: Distribution Stations capital increased by $32.7 million in 2025 compared to 2024, primarily reflecting the inclusion of projects that had been deferred due to the 2024 Rebasing Phase 1 capital reduction. The variance is primarily attributable to increased investment in the Stations with Auxiliary Equipment Replacement Program $18.1 million and the Distribution System Station Replacement Program $7.1 million. These increases reflect actions taken to address station security, resilience and operability risks, including the installation of auto transfer generators at high importance stations following a weather event.

Question(s):

Please provide more detail on the drivers, actions and expected benefits of station investments referred to in this evidence.

Response:

These programs address station condition, obsolescence, non-standard configurations, operability and reliability risks identified through inspections, condition assessments and risk assessments. The work includes targeted replacement or rebuilding of station components and, where warranted, replacement of stations to address identified risks. The expected benefits include maintaining safe and reliable operation, reducing the likelihood and consequence of equipment failure, maintaining service to customers, and improving station operability.

As part of the Stations with Auxiliary Equipment program, investments also address electrical, telemetry and backup-power requirements. The 2025 spending included installation of auto-transfer generators at high-importance stations following the ice-storm in March 2025 to improve station resilience and operability.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 2

Preamble:

TIS capital increased by $34.3 million in 2025 compared to 2024, primarily reflecting the execution of asset class strategies focused on addressing technology obsolescence, maintaining cyber security, and sustaining supported platforms. The largest contributor to the increase is continued investment in the Application Technology Obsolescence Program $25.3 million, including the ongoing Contract Market Modernization $21.1million. Additional increases reflect the Core Infrastructure and Security Renewal Program $4.4 million, Field Device Renewal Program $3.1 million.

Question(s):

For each of the three large drivers identified in the above preamble, please describe the project and why the increased expenditures were increased in 2025.

Response:

Application Technology Obsolescence Program

The Application Technology Obsolescence Program addresses technology obsolescence by modernizing applications and underlying technologies to maintain supported platforms. The increase in 2025 primarily reflects the progression of the Contract Market Modernization (CMM) program into the development and implementation phases (2025 $38.4 million vs 2024 $17.3 million).

CMM will address technology obsolescence and align the key systems and processes for contract markets, including Large Volume (LV) Distribution, Direct Purchase (DP), Storage and Transportation (S&T), and Gas Procurement & Gas Accounting.

Core Infrastructure and Security Renewal Program

The Core Infrastructure and Security Renewal Program replaces end-of-life infrastructure to address technology obsolescence and maintain cybersecurity. The increase in 2025 primarily reflects planned expenditures for the replacement of end-of-life network assets under the Software-Defined Wide Area Network (SD-WAN) program, with expenditures varying based on asset lifecycle and replacement timing.

Field Device Renewal Program

The Field Device Renewal Program replaces end-of-life field hardware supporting eGIS/GPS applications to address technology obsolescence and maintain supported platforms. The increase in 2025 primarily reflects planned expenditures for the replacement of end-of-life field devices, with expenditures varying based on asset lifecycle and replacement timing.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 2

Preamble:

EGI evidence states: This decrease was offset by increased spending in Class Location Program $8.5 million which was previously deferred, $4.7 million for land required for noise mitigation and to support safe operations, and Integrity $6.0 million to execute planned condition and risk-based activities.

Question(s):

For each program identified in the Preamble, please describe the program, the reason for increasing the amount in 2025.

a) Specifically for the Integrity expenditure, please describe fully how it is differentiated from DIMP and EDIMP while providing reasoning for the increase expenditure in 2025.

Response:

The expenditures identified in the preamble relate to Transmission Pipe and Underground Storage (TPUS) capital. Distribution Integrity Management Program (DIMP) and Enhanced Distribution Integrity Management Program (EDIMP) are entirely contained within the Distribution Pipe asset class.

The $8.5 million increase to the Class Location Program in 2025 was primarily for pipeline replacements required to address changes in population density adjacent to transmission pipelines and maintain safety and compliance.

The $4.7 million increase reflects land required for noise mitigation and to support safe operations. The expenditures are associated with property requirements necessary to support Enbridge Gas facilities and their safe operation.

a) Integrity expenditures comprise capital activities undertaken to identify, assess and mitigate integrity risks to Enbridge Gas assets. As described in previous Asset Management Plans, integrity management uses risk and condition information, including inspections, assessments, failure data and other asset information, to determine appropriate mitigation actions. Depending on the asset and identified risk, these actions can include continued monitoring, maintenance or repair, component replacement, or asset replacement.

   The $6.0 million increase in Integrity expenditures in 2025 reflects increased execution of planned condition- and risk-based Transmission Integrity Management Program (TIMP) activities, such as Digs, Retrofits, Independent Asset Integrity Review (IAIR), geotechnical hazards, and Depth of Cover Mitigation Program as well as Storage Downhole Integrity Management Program (SDIMP).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 2

Preamble:

EGI evidence states: The reduction is largely attributable to lower Meter Purchases ($12.5 million) resulting from fewer new customer additions and reduced spending in the Meter Exchange Government Inspection (MXGI) Program ($12.6 million). These reductions reflect volume-driven demand effects and planned inventory management, rather than changes in Utilization strategy or service standards

Question(s):

Please describe and provide numerical values for quantities or unit cost reductions for both programs.

a) Please describe any changes to Measurement Canada's criteria for meter testing and replacement or other reasons for the change driving the reduction.

Response:

The reductions in Meter Purchases and the Meter Exchange Government Inspection (MXGI) Program in 2025 were primarily related to lower purchasing requirements, meter exchange volumes and timing, and inventory management. Changes in meter unit prices were not a material driver of the year-over-year reduction.

Meter Purchases

The $12.5 million reduction primarily reflects fewer new customer additions and the resulting reduction in meter requirements. Lower customer additions since 2024 also resulted in higher-than-anticipated inventory of residential meters, which Enbridge Gas is continuing to use for new installations and meter exchanges, reducing the requirement for additional purchases.

Meter inventory was also comparatively higher following supply-chain constraints experienced during the COVID-19 pandemic. To manage delivery uncertainty, meter purchases were at times planned well in advance to secure supply. Combined with the subsequent reduction in customer additions, this contributed to available inventory and reduced the need for additional purchases in 2025.

MXGI Program

The $12.6 million reduction reflects the timing and volume of meter exchanges which are driven by the meter sampling program. The performance of sampled meter groups determines applicable seal-life extensions and whether meter groups require replacement, and previous-year sampling results inform subsequent meter exchange requirements.

a) There were no changes to Measurement Canada's meter testing or replacement requirements that drove the reduction in 2025. The MXGI Program continues to operate in accordance with Measurement Canada requirements. Meter seal life and extensions continue to be based on sampling and testing to determine meter-group health and replacement requirements.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 2

Preamble:

EGI evidence states: The decrease in this asset class in 2025 is primarily due to directly attributing costs to associated projects, partially offset by cost increases as part of the Lakeside renegotiated contract

Question(s):

Please quantify the increases as part of the Lakeside renegotiation contract.

a) Please confirm that they are a wholly owned company of Enbridge
b) Please describe the metrics Enbridge used to determine the appropriateness of agreeing to the increase

Response:

a) Lakeside Performance Gas Services Ltd. is a subsidiary of 2099634 Ontario Limited, which in turn is an indirect subsidiary of Enbridge Inc. The Ontario gas utility, Enbridge Gas Inc., has no ownership interest in Lakeside. Enbridge is not involved in Lakeside's day-to-day operations or management.

b) Enbridge Gas put the work included in the Lakeside contract to a competitive RFP and Lakeside was determined to have the best proposal. The competitively bid contract reflected current market rental rates across Lakeside’s service locations, including inflationary and demand-driven cost increases. It also incorporated expanded service requirements, including QA/QC, photographic documentation, and inventory management responsibilities.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 3, Schedule 2

Preamble:

EGI evidence states: Other spend decreased by ($15.7 million) in 2025 compared to 2024. This is primarily driven by Watford (Twin Creeks) RNG pipeline project substantial completion in 2024 and reduced capital requirements in 2025 resulting in a ($16.1 million) decrease.

Question(s):

For the Watford (Twin Creeks) RNG pipeline project, who paid for the project and, how any aid-to-construction has been included in this evidence?

Response:

The project was funded through Enbridge Gas's capital program, with no upfront Contribution in Aid of Construction. In accordance with the E.B.O. 188 economic feasibility assessment filed in the Watford RNG Project[1], the project costs are recovered from Waste Management through the monthly service charge under the long-term M13 service contract. As confirmed in OEB's Decision and Order[2], all actual project costs are to be paid by Waste Management and not borne by other ratepayers. The capital expenditures in this evidence reflect Enbridge Gas's project expenditures.

[1] EB-2023-0175.
[2] EB-2023-0175, Decision and Order, March 7, 2024.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, Page 2, Table 1 and
EB-2024-0125 Exhibit D, Tab 1

Preamble:

In the second reference, EGI provided steps taken that lead to a significant reduction in UFG for 2023. With the recent two years escalation in UFG, we would like to understand better how those initiatives outlined in that Deferral Disposition proceeding evidence are continuing and reducing UFG

Question(s):

For each initiative cited in the 2023 Deferral Disposition evidence:

a) Which initiatives have been continued

b) What results has EGI seen

c) What enhancements have been developed in those initiatives

Response:

a) and c) Please see Attachment 1.

a) Although Enbridge Gas continues to pursue the initiatives outlined in Attachment 1, given the wide range of factors that can impact overall Unaccounted for Gas (UFG), and the point-in-time reporting, not all initiatives directly reduce UFG volumes it is not possible to determine the impact of the individual initiatives separately.

UFG Initiatives

Line No.	Initiatives	Status	Developments
1	Participation in Industry Groups/Associations, & Cross-Functional Measurement Groups	On-going	EGI continues to participate in all groups identified in 2023 evidence.
2	Work to Update Gas Quality Parameters	Completed	
3	Work to Eliminate a Backlog of Leaks	Completed	Leaks continue to be monitored and included in the Fugitive emission inventory.
4	Various Meter Reading Campaigns & Initiatives	On-going	Initiatives continue to improve meter reading performance and increase opportunities to obtain actual meter reads, including targeted customer outreach and self-read programs, enhanced field activities for difficult-to-access and consecutive-estimate accounts, strengthened validation controls, and deployment of more than 148,000 AMR meters since January 2025. Please see G-1-3 for further updates.
5	Vacant Premises Backlog	On-going	EGI has experienced an increase in vacant premises in the last two years and is undertaking efforts to address and clear these accounts. Vacant premises are a normal aspect of ongoing operations, and periodic fluctuations are expected.
6	Assessment of Storage Inventory Audits and Adjustments	Annual	Please see response at Exhibit I STAFF-1
7	Advanced Metering Infrastructure	On-going	Please see response at Exhibit I CCC-9
8	Pressure Elevation Factors	Completed	Updated SAP CIS to correct PEFs across Union Rate Zones for 2021-2023.
9	Loss of Containment (Gas Loss Due to Damage Events)	On-going	Volumes are a part of Fugitive emission inventory.
10	Measurement Integration Large Volume Customer Measurement for Power Generation	Completed On-going	EGI's applicable measurement design standards have been updated to ensure that new installations are appropriately configured to accurately measure both high-flow and low-flow operating conditions at these customers. For existing installations, Enbridge Gas' efforts have primarily focused on understanding the extent of the issue and evaluating potential mitigation options at select sites. Experience to date has shown that remediation is highly site-specific and often requires modifications to customer-owned gas piping and facilities to enable separate measurement of low-flow loads. As a result, any corrective actions would need to be assessed on a case-by-case basis, considering technical feasibility, customer impacts, and overall cost-effectiveness. Enbridge Gas will continue to apply the updated design standards to new installations and will consider lessons learned from future assessments of existing facilities as opportunities arise.
11	Operational Emission Reductions	On-going	In December 2025, the federal government published amendments to the Federal Regulations Respecting Reduction in the Release of Methane and Certain Organic Volatile Organic Compounds (Upstream Oil and Gas Sector) (amended methane regulations), with the objective to further reduce methane from the oil and gas sector. Although the majority of UFG contributing sources identified, investigated, and quantified do not represent any form of physical gas loss to atmosphere, it is anticipated that the amended methane regulations will have a positive impact on UFG.
12		On-going	
13	No-Bills exceptions and reduction of time to make corrections	Completed	
14	No-Bills estimation Process	On-going	Work completed thus far allows the use of more relevant factors when calculating the monthly volumes, which increases the accuracy of accruals.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 3, Page 2, Table 1 and
EB-2024-0125 Exhibit D, Tab 1

Preamble:

In the second reference, EGI provided steps taken that lead to a significant reduction in UFG for 2023. With the recent two years escalation in UFG, we would like to understand better how those initiatives outlined in that Deferral Disposition proceeding evidence are continuing and reducing UFG

Question(s):

Please provide a description of any additional UFG mitigating initiatives that EGI has undertaken in the last couple years and quantify the estimated impact on the volumes allocated to UFG.

Response:

Table 1 provides the focus areas of additional unaccounted for gas (UFG) investigations. As these are active investigations, Enbridge Gas is not able to provide an estimate of the impact on volumes allocated to UFG beyond what is provided at Exhibit I.STAFF-1.

Table 1
UFG Focus Areas

Line No.	Focus Areas	Description
1	Gas Meter Accuracy and Uncertainty	Review of customer measurement accuracy
2	Estimations (Billed, No-bill, Unbilled)	Review of internal billing estimation processes and potential impact on UFG reporting. Please see Exhibit G-1-3
3	Prior Period Adjustments	Review of impact of prior period billing adjustments
4	Gate Station Measurement Variation	Review of gate station measurement accuracy
5	Gas Accounting Adjustments	Review of gas accounting adjustments relating to timing of sendout/consumption reporting and heat value
6	Company Use	Validation of own use gas meters
7	Heat Value Variances	Review of variances between billed and actual heat value and resulting impact

Enbridge Gas has spent significant effort evolving its approach to uncover potential sources of UFG to an approach that relies on advanced analytics using emerging data intelligence tools. The intent of this initiative is to better identify and quantify potential sources of UFG using new AI-enabled analytical tools now available to Enbridge Gas. Enbridge Gas has been exploring available options to enable this work and is in the implementation phase now. Enbridge Gas expects to begin using these new tools in 2027.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 6, Page 2

Preamble:

We would like to understand more about the operational notice issued in 2025 regarding a pressure restriction on the NPS 26 Trafalgar pipeline.

Question(s):

Please file the Operational Notice issued in 2025.

a) Please describe the underlying reasons for the pressure restriction.
b) Please identify and describe the mitigating and/or rehabilitation steps EGI has undertaken to restore the previous pressure capability.
    i. If none have been taken, please explain why.

Response:

Below is the operational notice sent to customers:

As a result of our ongoing integrity program, Enbridge Gas is imposing a pressure restriction on the NPS 26 Trafalgar pipeline. Until further notice, some requests for interruptible services may not be scheduled on the following paths:

1. the Dawn to Parkway transportation path;
2. the Dawn to Kirkwall transportation path; and
3. the Kirkwall to Parkway transportation path.

The operational notice can be found at: www.enbridgegas.com/storage-transportation/operational-information/operational-status

a-b) The restriction is due to an integrity feature identified along sections of the NPS 26 Dawn Parkway pipeline. Enbridge Gas will be filing a leave to construct application to address the restoration of the NPS 26 pipeline capacity and details related to mitigation and/or rehabilitation options will be discussed in that proceeding.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 18

Preamble:

We would like to understand better the determination of Average Use

Question(s):

Please provide a description and Excel spreadsheet(s) showing the determination of the 2025 Forecasted Average Use and the 2025 Actual Average Use.

a) Does EGI perform any audits or tests to determine if its customer numbers are correct and the determinations are rigorous.

Response:

Please see Attachment 1 which shows the determination of the annual 2025 forecasted average use and the 2025 actual normalized average use shown at line 1 and 2, respectively, of Exhibit C, Tab 2, Schedule 18, Attachment 1. For a more detailed calculation of the 2025 actual normalized average use, please see Exhibit I.FRPO-2, Attachment 2.

a) The annual average customer numbers at line 4 of Exhibit C, Tab 2, Schedule 18, Attachment 1, which are used to determine normalized volumetric variance at line 5, are the 2024 OEB-approved customers, including the adjustment agreed to in the 2024 Rebasing Phase 1[1] Settlement Proposal. These numbers remain unchanged between rebasing applications.

   Actual customer numbers in Attachment 1, which are used to determine actual normalized average use, are validated against the customer count in the billing system.

[1] EB-2022-0200.

Table 1
2025 Actual Customers by Rate Class for the General Service Market

Line No.	Rate Class	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	2,173,651	2,174,980	2,176,191	2,177,219	2,177,078	2,176,928	2,177,480	2,178,705	2,180,388	2,184,028	2,187,422	2,189,545	2,179,468
2	Rate 6	174,272	174,367	174,274	174,155	173,650	173,343	173,204	173,275	173,400	174,191	175,012	175,414	174,046
3	Rate M1	1,207,953	1,208,000	1,208,909	1,211,121	1,210,449	1,211,437	1,213,459	1,213,535	1,214,552	1,217,445	1,216,282	1,216,607	1,212,479
4	Rate M2	10,086	10,285	10,036	10,044	9,925	9,733	9,597	9,485	8,929	8,462	8,518	8,523	9,469
5	Rate 01	371,827	371,877	372,027	372,387	372,283	372,496	373,112	373,064	373,364	374,163	373,943	373,999	372,879
6	Rate 10	2,763	2,808	2,744	2,735	2,698	2,706	2,626	2,600	2,364	2,228	2,242	2,232	2,562
7	EGI	3,940,552	3,942,317	3,944,181	3,947,661	3,946,083	3,946,643	3,949,478	3,950,664	3,952,997	3,960,517	3,963,419	3,966,320	3,950,903

Table 2
2025 Actual Weather Normalized Volumes by Rate Class for the General Service Market (m3)
Volumes normalized to 2025 Heating Degree Days (HDDs)

Line No.	Rate Class	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	880,836,407	754,343,361	663,688,111	410,118,890	189,387,136	102,354,845	153,952,745	119,757,326	122,965,702	247,723,906	533,919,334	728,696,661	4,907,744,425
2	Rate 6	864,808,305	785,065,055	660,185,440	471,349,640	210,492,081	91,719,299	90,813,380	107,038,932	130,236,820	196,056,124	499,718,430	716,487,138	4,823,970,643
3	Rate M1	532,768,297	464,867,025	418,354,441	284,495,066	113,952,830	71,357,451	92,036,884	73,989,458	79,685,541	141,848,710	354,785,348	446,792,444	3,074,933,495
4	Rate M2	174,382,426	197,688,770	141,674,526	126,769,110	66,098,440	38,655,299	42,751,093	36,218,118	48,417,003	87,679,362	143,252,112	167,589,548	1,271,175,808
5	Rate 01	184,096,250	141,340,677	133,651,104	88,802,104	36,697,528	16,373,004	22,380,216	19,497,314	20,025,525	53,709,625	111,819,625	147,885,160	976,278,134
6	Rate 10	45,148,184	50,682,956	33,561,802	28,725,994	13,555,466	7,511,896	10,732,719	3,921,954	17,749,322	22,365,320	33,813,352	41,466,202	309,235,166
7	EGI	2,682,039,870	2,393,987,845	2,051,115,424	1,410,260,805	630,183,480	327,971,793	412,667,038	360,423,103	419,079,913	749,383,047	1,677,308,201	2,248,917,153	15,363,337,671

Table 3
2025 Actual Weather Normalized Average Use for the General Service Market (m3)
Average Use normalized to 2025 HDDs

Line No.	Rate Class	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	405	347	305	188	87	47	71	55	56	113	244	333	2,252
2	Rate 6	4,962	4,502	3,788	2,706	1,212	529	524	618	751	1,126	2,855	4,085	27,659
3	Rate M1	441	385	346	235	94	59	76	61	66	117	292	367	2,538
4	Rate M2	17,290	19,221	14,117	12,621	6,660	3,972	4,455	3,818	5,422	10,362	16,818	19,663	134,418
5	Rate 01	495	380	359	238	99	44	60	52	54	144	299	395	2,619
6	Rate 10	16,340	18,049	12,231	10,503	5,024	2,776	4,087	1,508	7,508	10,038	15,082	18,578	121,726
7	EGI	681	607	520	357	160	83	104	91	106	189	423	567	3,889

Table 4
2025 Forecast Customers by Rate Class for the General Service Market

Line No.	Rate Class	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	2,177,584	2,180,592	2,179,351	2,182,180	2,183,173	2,183,255	2,184,801	2,182,333	2,184,295	2,184,942	2,187,120	2,191,176	2,183,400
2	Rate 6	171,687	171,806	171,592	171,697	171,658	171,546	171,548	171,238	171,273	171,205	171,259	171,459	171,497
3	Rate M1	1,211,756	1,213,261	1,212,399	1,213,804	1,214,185	1,214,060	1,214,748	1,213,208	1,214,126	1,214,315	1,215,355	1,217,437	1,214,055
4	Rate M2	8,128	8,138	8,130	8,138	8,139	8,137	8,139	8,129	8,134	8,133	8,138	8,151	8,136
5	Rate 01	372,937	373,374	373,082	373,486	373,577	373,512	373,696	373,196	373,451	373,482	373,776	374,390	373,497
6	Rate 10	2,280	2,282	2,280	2,282	2,282	2,282	2,282	2,278	2,279	2,279	2,280	2,283	2,281
7	EGI	3,944,372	3,949,453	3,946,834	3,951,587	3,953,014	3,952,792	3,955,214	3,950,382	3,953,558	3,954,356	3,957,928	3,964,896	3,952,866

Table 5
2025 Forecast Volumes by Rate Class for the General Service Market (m3)

Line No.	Rate Class	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	929,658,584	819,678,724	693,287,300	433,530,226	190,973,017	104,070,545	104,053,698	103,844,432	104,878,789	257,901,820	533,212,684	767,721,288	5,042,811,106
2	Rate 6	775,929,028	758,717,431	657,868,912	452,364,003	226,143,706	144,497,828	105,284,003	104,960,646	144,582,672	224,826,350	436,721,681	641,000,306	4,672,896,566
3	Rate M1	589,840,658	514,198,484	437,124,870	286,192,619	123,827,191	72,878,408	73,057,871	70,387,988	74,015,881	148,964,183	345,937,329	479,218,567	3,215,644,052
4	Rate M2	162,800,370	185,975,540	155,781,012	101,310,703	60,367,867	46,540,560	38,732,118	42,863,599	45,111,373	87,407,480	137,760,587	167,330,957	1,231,982,167
5	Rate 01	195,788,887	159,372,597	138,007,373	90,482,799	39,895,495	16,771,498	17,095,083	16,997,026	18,786,277	52,191,266	110,852,931	155,827,040	1,012,068,271
6	Rate 10	43,239,088	49,386,458	40,216,936	26,235,857	16,746,993	9,384,482	9,030,260	9,052,867	10,308,686	22,130,938	36,536,534	46,469,566	318,738,665
7	EGI	2,697,256,615	2,487,329,234	2,122,286,403	1,390,116,206	657,954,269	394,143,321	347,253,033	348,106,559	397,683,678	793,422,037	1,601,021,747	2,257,567,724	15,494,140,826

Table 6
2025 Forecast Average Use by Rate Class for the General Service Market (m3)

Line No.	Rate Class	Jan-2025	Feb-2025	Mar-2025	Apr-2025	May-2025	Jun-2025	Jul-2025	Aug-2025	Sep-2025	Oct-2025	Nov-2025	Dec-2025	Annual Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate 1	427	376	318	199	87	48	48	48	48	118	244	350	2,310
2	Rate 6	4,519	4,416	3,834	2,635	1,317	842	614	613	844	1,313	2,550	3,739	27,236
3	Rate M1	487	424	361	236	102	60	60	58	61	123	285	394	2,649
4	Rate M2	20,030	22,853	19,161	12,449	7,417	5,720	4,759	5,273	5,546	10,747	16,928	20,529	151,411
5	Rate 01	525	427	370	242	107	45	46	46	50	140	297	416	2,710
6	Rate 10	18,965	21,642	17,639	11,497	7,339	4,112	3,957	3,974	4,523	9,711	16,025	20,355	139,738
7	EGI	684	630	538	352	166	100	88	88	101	201	405	569	3,920

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 14, Page 10

Preamble:

EGI evidence states: The Corrosion Survey work category included above-ground surveys such as Cathodic Protection (CP) system surveys and non-intrusive pipeline assessments (NIPA).

Question(s):

What elements of the components of this work would qualify the work as EDIMP versus traditional Operational and Maintenance due diligence of a natural gas utility?

a) Please define these components and their output that distinguishes them as EDIMP qualified.

Response:

a) Please see Exhibit G, Tab 4, Schedule 1, pages 13 to 14 for information on the Enhanced Distribution Integrity Management Program (EDIMP) incremental corrosion surveys and new assessment technologies.

   Regional Operations continues to monitor the pipeline cathodic protection system on regular intervals and complete repairs (e.g., anode installations, rectifier adjustments) to maintain adequate protection of steel pipelines. These activities are part of routine Operating and Maintenance (O&M) programs.

   The objective of EDIMP is to assess the condition of critical distribution pipelines to support long-term asset management strategies. The following activities distinguish EDIMP work from traditional O&M activities:

   1) Enhanced Corrosion Surveys:
      - Close Interval Potential Surveys (CIPS) are completed to identify areas of insufficient cathodic protection at a higher resolution than routine

monitoring through corrosion test points. This survey is used to identify areas of elevated corrosion susceptibility.

- Direct Current Voltage Gradient (DCVG) surveys are completed to identify areas of the pipeline that may have coating defects, which can also indicate areas of elevated corrosion susceptibility.
- Collectively, CIPS and DCVG surveys also support planning of the segments of pipe that should be inspected by ILI, ensuring the results will be representative of the entire pipeline.

2) Advanced Assessment Technology:

- The Non-Intrusive Pipeline Assessment method is a new technology that, if validated, may offer an alternative to assessing the condition of an entire pipeline without the need to complete an inline inspection. This approach has not previously been used by Enbridge Gas.

The EDIMP activities described above aim to provide detailed condition-based asset information above and beyond traditional O&M activities.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, Page 4 including Table 2

Preamble:

The above referenced table presents a comparison of MBS and Alternatives. We would like to understand how these numbers were derived.

Question(s):

For each of the line items in the table, please provide:

a) A description of the determination process including all assumptions and reference to input parameters that are drawn from the market, if any.
b) A working Excel spreadsheet that provides the determination of the resulting annualized cost.

Response:

a) The methodologies applied to calculate annualized costs of each of the alternatives included in Table 2, by line item, are described below:

   Line 1: High-Flexibility MBS Annualized Cost

   The annualized cost per GJ of High-Flexibility Market Based Storage (MBS) was calculated as the sum of the average annual summer commodity cost and the total annual cost of the storage service offered for a five-year term. The average summer commodity cost was calculated using the average monthly forward Dawn gas prices for May to September as of February 25, 2025 (i.e., market settlement prices for the day prior to the close of the Blind RFP), over a five-year term (2025 to 2030) of the High-Flexibility storage service offer recommended by the Blind RFP Manager. Storage service costs include all applicable demand, commodity and fuel charges.

Line 2: Low-Flexibility MBS Annualized Cost

The annualized cost per GJ of Low-Flexibility MBS was calculated as the sum of the average annual summer commodity cost and the total annual cost of the storage service offered over a five-year term. The average summer commodity cost was calculated using the average monthly forward Dawn gas prices for May through September as of February 25, 2025 (i.e., market settlement prices for the day prior to the close of the Blind RFP), over a five-year term (2025 to 2030) of the Low-Flexibility storage service provided by the Blind RFP Manager. This offer was not recommended by the Blind RFP Manager. Storage service costs include all applicable demand and commodity charges.

Line 3: Delivered Supply

The annual Delivered Supply cost per GJ was calculated as the average of the monthly forward Dawn gas prices for December 2025 to February 2026 as of February 25, 2025 (i.e., market settlement prices for the day prior to the close of the Blind RFP).

b) Please see Attachment 1.

Table 1
Calculation of Annualized Cost

Line No.	Annualized Costs (CAD/GJ)	High-Flexibility MBS (a)	Low-Flexibility MBS (b)	Delivered Supply (c)
1	Storage Charges	[redacted]		*N/A*
2	May to Sep. Commodity Cost (Table 2, line 61)			*N/A*
3	Dec. to Feb. Commodity Cost (Table 2, line 11)	*N/A*	*N/A*	6.210
4	Annualized Cost	5.681	5.429	6.210

Table 2: Monthly Dawn Forward Price as of February 25, 2026

Line No.	Month	NYMEX (CAD/GJ) (a)	Dawn Basis (CAD/GJ) (b)	Dawn (CAD/GJ) (c)=(a)+(b)	May to Sep. Average Commodity Cost (CAD/GJ) (d)=avg(c)	Dec. to Feb. Average Commodity Cost (CAD/GJ) (e)=avg(c)
1	April 2025	[redacted]				
2	May 2025					
3	June 2025					
4	July 2025					
5	August 2025					
6	September 2025					
7	October 2025					
8	November 2025					
9	December 2025					
10	January 2026					
11	February 2026					6.210
12	March 2026					
13	April 2026					
14	May 2026					
15	June 2026					
16	July 2026					
17	August 2026					
18	September 2026					
19	October 2026					
20	November 2026					
21	December 2026					
22	January 2027					
23	February 2027					
24	March 2027					
25	April 2027					
26	May 2027					
27	June 2027					
28	July 2027					
29	August 2027					
30	September 2027					
31	October 2027					
32	November 2027					
33	December 2027					
34	January 2028					
35	February 2028					
36	March 2028					
37	April 2028					
38	May 2028					
39	June 2028					
40	July 2028					
41	August 2028					
42	September 2028					
43	October 2028					
44	November 2028					
45	December 2028					
46	January 2029					
47	February 2029					
48	March 2029					
49	April 2029					
50	May 2029					
51	June 2029					
52	July 2029					
53	August 2029					
54	September 2029					
55	October 2029					
56	November 2029					
57	December 2029					
58	January 2030					
59	February 2030					
60	March 2030					
61	May to September Five-Year Average					

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1, Page 4 including Table 2

Preamble:

EGI evidence states: The forecast storage requirement for the 2025/26 gas year using the aggregate excess methodology was 3 PJ lower than the storage requirement that informed the Company's 2024 Rebasing forecast (215 PJ vs. 218 PJ, respectively). The storage requirement was forecast to increase by 3 PJ for the 2027/28 gas year (to 218 PJ again)

Question(s):

For each of the two load balancing needs identified, please provide:

a) a description of the determination methodology including all assumptions
b) a working Excel spreadsheet that shows the determination

Response:

a-b) The storage requirements referenced in the preamble were determined using the Aggregate Excess methodology, as described in Section 5.4 of Enbridge Gas's 5-Year Gas Supply Plan[1].

Attachment 1 provides the calculation supporting the 2025/26 storage requirement forecast of 215 PJ, as well as the calculation supporting the 218 PJ storage requirement forecast used in the 2024 Rebasing Phase 2 proceeding[2].

[1] EB-2025-0065.
[2] EB-2024-0111, Exhibit I.4.2-FRPO-46.

Enbridge Gas 2025/26 Storage Requirement

Line No.	Particulars (TJ)	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sept-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Demand Forecast (1)	67,079	37,038	25,222	23,145	23,202	25,532	43,338	76,573	103,491	122,394	113,152	98,677
	Total storage requirement												
2	Aggregate excess (2)	200,355											
3	Semi-unbundled storage	14,375											
4	Total storage requirement	214,730											

Notes:

(1) Demand forecast excludes semi-unbundled demands.

(2) Aggregate excess calculated as the difference between winter consumption (November to March) less annual average consumption multiplied by 151 days.

Enbridge Gas 2024/25 Storage Requirement

Line No.	Particulars (TJ)	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Demand Forecast (1)	66,977	37,032	24,862	22,982	23,126	25,254	42,332	76,937	103,066	123,433	114,063	99,337
	Total storage requirement												
2	Aggregate excess (2)	202,673											
3	Semi-unbundled storage	15,077											
4	Total storage requirement	217,750											

Notes:

(1) Demand forecast excludes semi-unbundled demands.

(2) Aggregate excess calculated as the difference between winter consumption (November to March) less annual average consumption multiplied by 151 days.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, Pages 3-4 including Table 1

Preamble:

We would like to understand better the forecasting, allocating for rate setting and the subsequent actual paths that were not used for supply and the contribution to allocations.

Question(s):

For each of the respective Union Rate zones in Table 1, please provide:

a) The paths that were forecasted to be used for UDC
b) The rates used for incorporation in rate
c) The monthly periods forecasted to be unutilized for supply.

Response:

a) Consistent with the Company's 5-Year Gas Supply Plan,[1] the transportation paths with planned unutilized capacity are summarized below.

Union North West rate zone

- Empress to Union MDA
- Empress to Union SSMDA
- Empress to Union WDA

Union North East rate zone

- Empress to Union NCDA

[1] EB-2025-0065, 5-Year Gas Supply Plan, Section 5.3, Table 7, pp. 44-45.

- Empress to Union EDA
- Empress to Union NDA
- Parkway to Union EDA
- Parkway to Union NCDA

The unutilized demand charges recorded in the Unutilized Demand Charge Variance Account are determined based on actual operating conditions and system requirements, not on planned unutilized capacity.

b) Please see response at Exhibit I.FRPO-21, Attachment 1.

c) Planned unutilized capacity is determined monthly as part of the Gas Supply Plan supply and demand forecasting process. 2025 monthly planned unutilized capacity figures are included in Attachment 1.[2]

[2] The planned unutilized capacity amounts presented in the gas supply plan are based on gas year. Accordingly, the planned amounts for January to October 2025 reflect the amounts set out in the Company's 5-Year Gas Supply Plan (EB-2025-0065, 5-Year Gas Supply Plan, Section 5.3, Table 7, p. 45) and the planned amounts for November and December 2025 reflect the amounts set out in the Company's 2026 Annual Gas Supply Plan Update (EB-2026-0092, 2026 Annual Gas Supply Plan Update, Section 3.3, Table 8, p. 21).

2025 Planned Unutilized Capacity

Line No.	Particulars (TJ)	January	February	March	April	May	June	July	August	September	October	November	December	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	North West:													
1	Empress to Union MDA	66	60	83	88	-	-	161	160	155	135	97	83	1,088
2	Empress to Union SSMDA	-	-	567	-	-	-	-	-	-	263	24	-	854
3	Empress to Union WDA	-	-	1,378	-	-	-	-	-	481	981	489	186	3,515
4	Subtotal	66	60	2,028	88	-	-	161	160	636	1,379	610	269	5,457
	North East:													
5	Empress to Union NCDA	31	28	31	-	-	-	-	-	-	-	30	31	151
6	Empress to Union EDA	155	140	155	-	-	-	-	-	-	-	150	155	755
7	Empress to Union NDA	-	-	65	-	-	-	-	-	-	-	-	-	65
8	Parkway to Union EDA	1,051	920	1,161	1,124	1,161	1,124	1,161	1,161	1,124	1,161	-	-	11,148
9	Parkway to Union NCDA	170	153	89	44	45	44	45	45	43	44	-	-	722
10	Subtotal	1,407	1,241	1,501	1,168	1,206	1,168	1,206	1,206	1,167	1,205	180	186	12,841
11	Total Planned Unutilized Capacity	1,473	1,301	3,529	1,256	1,206	1,168	1,367	1,366	1,803	2,584	790	455	18,298

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 1, Pages 3-4 including Table 1

Preamble:

We would like to understand better the forecasting, allocating for rate setting and the subsequent actual paths that were not used for supply and the contribution to allocations.

Question(s):

For each of the respective Union Rate zones in Table 1, please provide:

a) The actual paths that were not used for a period during 2025
b) The month(s) or shorter periods if applicable during which the path was not used for gas supply.
c) The actual rate associated with that path when unutilized for gas supply
d) The reconciliation methodology and specific determination of the UDC allocated to each respective rate zone. Please provide the determination in an Excel spreadsheet.

Response:

a-c) Please see Attachment 1 for an Excel spreadsheet detailing actual monthly UDC unit rates by path and delivery area (within the Union rate zones) for 2025.[1]

d) Consistent with the evidence[2] UDC Cost Incurred and Released Capacity Revenue are re-allocated to the Union North East, Union North West, and Union South rate zones in proportion to the actual supply and consumption variances for 2025. Please see Attachment 2 for an Excel spreadsheet detailing the re-allocation calculation.

[1] Certain of the paths identified in Attachment 1 may be unutilized for less than one month (e.g., due to short-duration maintenance events occurring within a month).
[2] Exhibit E, Tab 1, Schedule 1, Table 2, Note 1.

Actual Monthly UDC Unit Rates by Path and Delivery Area (Union Rate Zones)

Delivery Area	Pipeline	Receipt Point	Delivery Point	UDC Cost Incurred (CAD/GJ/Day)	2025 Activity Month
	(a)	(b)	(c)	(d)	(e)
Union North East					
	TCPL	Union Parkway Belt	Union EDA	0.2836	January
				0.2836	February
				0.2836	March
				0.2836	April
				0.2836	May
				0.2836	June
				0.2836	July
				0.2836	August
				0.2836	September
				0.2836	October
				0.2836	November
	NEXUS	Clarington	St. Clair	1.4651	April
				1.4517	May
				1.4321	June
				1.4491	September
				1.4656	October
	NEXUS	Kensington	St. Clair	1.1803	January
				1.1470	April
				1.1365	May
				1.1212	June
				1.1231	August
				1.1344	September
				1.1473	October
Union North West					
	TCPL	Empress	Centrat MDA	0.3193	April
				0.3193	May
				0.3193	June
				0.3193	July
				0.3193	August
				0.3193	September
				0.3193	October
	TCPL	Empress	Union SSMDA	0.6276	January
				0.6276	February
				0.6276	March
				0.6276	April
				0.6276	May
				0.6276	June
				0.6276	July
				0.6276	August
				0.6276	September
	TCPL	Empress	Union WDA	0.4507	April
				0.4507	May
				0.4507	June
				0.4507	July
				0.4507	August
				0.4507	September
				0.4507	October
				0.4507	October
				0.4507	November
				0.4507	December
Union South					
	TCPL	Empress	Emerson 2	0.3449	January
				0.3449	August
				0.3449	September
				0.3449	October
				0.3449	November
				0.3449	December
	Great Lakes	Emerson 2	Dawn	0.3820	January
				0.3642	August
				0.3677	September
				0.3734	October
				0.4145	November
				0.4072	December
	NEXUS	Clarington	St. Clair	1.4651	April
				1.4517	May
				1.4321	June
				1.4491	September
				1.4656	October
	NEXUS	Kensington	St. Clair	1.1803	January
				1.1470	April
				1.1365	May
				1.1212	June
				1.1231	August
				1.1344	September
				1.1473	October
	Niagara	Niagara Falls	Kirkwall	0.1595	March
	PEPL	PEPL Field Zone	Ojibway	0.6036	April
				0.5980	May
	Vector	Vector	Dawn	0.2129	July

Re-Allocation of UDC Cost Incurred

Line No.	Particulars	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	Supply-Related UDC Variances (PJ)	3.2	1.4	15.1	19.7
2	Consumption-Related UDC Variances (PJ)	7.0	2.7	3.1	12.8
3	Total UDC Variances (PJ)	10.2	4.1	18.2	32.5
4	Allocation Percentage (1)	31%	13%	56%	100%
5	UDC Cost Incurred ($000's) (2)	4,829	1,971	8,648	15,449
6	Capacity Release Revenues ($000's) (2)	1,452	593	2,600	4,645

Notes:

(1) The allocation percentage is determined based on each rate zone's proportionate share of actual supply and consumption variances for the 2025 calendar year.

(2) Total per updated Exhibit E, Tab 1, Schedule 1, Table 2, allocated to rate zones in proportion to Line 4.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 2, Page 3 including Table 1

Preamble:

With the evolution of utility storage upon integration, we would like to understand better the services provided by the utility vs. non-utility.

Question(s):

For each line item in Table 1, please provide:

a) the Actual revenue from 2020 to 2025.
b) a description of the feasibility of the services provided by the utility storage
c) how market-based requests for services are handled between the utility and the non-utility storage resources

Response:

a) Please see Table 1 for actual revenue from 2020 to 2025.

Table 1
2020-2025 Storage Revenue

Line No.	Particulars ($ millions)	2020	2021	2022	2023	2024	2025
		(a)	(b)	(c)	(d)	(e)	(f)
1	Peak Storage	1.0	1.5	2.1	2.6	0.9	0.2
2	Off-Peak Storage	1.0	0.4	0.1	1.0	2.4	0.0
3	Loans	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0
4	Short-term Balancing	2.7	0.6	1.0	0.9	2.0	0.4
		4.7	2.6	3.3	4.6	5.3	0.6

b) Prior to the implementation of the 2024 Rebasing Phase 2 Settlement Agreement, the Union Rate Zone had excess utility storage space which underpinned the sale of short-term storage and other balancing services. After the implementation of the 2024 Rebasing Phase 2 Settlement Agreement there was no longer excess utility storage available for sale. The last deals underpinned by excess utility storage ended on April 1, 2025.

c) Prior to integration, Enbridge Gas prioritized the sale of utility storage ahead of the sale of its short-term non-utility storage and allocated short-term peak storage margins between utility and non-utility as directed by the OEB in Union's 2013 Cost of Service Decision[1]. After the implementation of the 2024 Rebasing Phase 2 Settlement agreement, all market-based requests are fulfilled using non-utility storage as there is no excess utility storage space available for sale.

[1] EB-2011-0210, OEB Decision and Order, October 24, 2012, pp.116-117.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit E, Tab 1, Schedule 2, Page 3 including Table 1

Preamble:

With the evolution of utility storage upon integration, we would like to understand better the services provided by the utility vs. non-utility.

Question(s):

For each of the costs identified in lines 7-10, please provide:

a) the amount of compensation provided by the non-utility storage
b) How each of those costs are determined

Response:

a) Enbridge Gas has credited the 10% shareholder portion of the costs to the ratepayer in the amount of $0.05 million, as shown in Exhibit E, Tab 1, Schedule 2, page 3, Line 11.

b) The O&M cost of $0.04 million is the revenue requirement associated with excess in-franchise storage capacity of 0.4PJ in 2025 relative to the total revenue requirement for the 2013 OEB-approved excess in-franchise storage capacity of 11.3PJ of $3.8 million.

   The UFG cost of $0.32 million was determined based on actual January to March 2025 activity and the corresponding unaccounted for gas (UFG) costs incurred in the Union rate zones during that period. The allocation of UFG was calculated using a volumetric allocator derived from the ratio of short-term storage activity volumes to total throughput volumes for January through March 2025. Total throughput volumes include in-franchise and ex-franchise throughput volumes, as well as storage injection and withdrawal volumes.

The compressor fuel cost of $0.11 million was determined by using an allocator based on the ratio of short-term storage activity to total storage activity. This allocator is applied to the compressor fuel costs for storage incurred from January to March 2025.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 4, Schedule 1

Preamble:

We would like to understand better the EDIMP program and the associated ratepayer benefits.

Question(s):

Please provide the working definition used by EGI to differentiate DIMP-related work and EDIMP-related work.

a) In addition, please clarify how DIMP-related work is differentiated from historic Operating and Maintenance practices of the legacy utilities.

Response:

As referenced in the 2024 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding[1] at Exhibit I.PP-6 response part b), the Distribution Integrity Management Program (DIMP) scope includes all gas carrying distribution assets from upstream custody transfer points (i.e., gate stations) to downstream customer meters, including the following:

- Pipe: Gas distribution mains operating at <30% Specified Minimum Yield Strength (SMYS), headers, services, risers, valves, fittings (excluding the Enhanced Distribution Integrity Management Program (EDIMP) pipelines as described below)
- Stations: Distribution system stations (excluding Facilities Integrity Management Program (FIMP) scope) and customer stations
- Regulator Sets: Farm taps, commercial and residential meter sets, service extensions

[1] EB-2025-0155.

The EDIMP was created as a sub-program within DIMP to further evaluate distribution steel pipelines that meet one or more of the following criteria:

- Operate at 20% to 30% SMYS
- Are classified as vital mains or equivalent
- Have a Maximum Operating Pressure (MOP) ≥ 1200 kPa (175 psi) and a pipe diameter ≥ NPS 6

a) The DIMP and Operations & Maintenance (O&M) activities serve different purposes. DIMP uses data generated through O&M activities to identify and evaluate system risks, implement measures to reduce those risks, and direct resources toward activities that provide the greatest reduction in risk relative to cost. O&M activities, however, generally focus on the daily operation, inspection, maintenance, and repair of distribution assets to ensure the system is operated safely, reliably, and in compliance with applicable regulatory requirements.

   DIMP's purpose is to develop a holistic understanding of the distribution system, identify system threats, evaluate and prioritize associated risks, and implement measures to address those risks. DIMP evaluates data generated through O&M activities, including leak surveys, leak investigations, system repairs, asset inspections, and emergency response activities to determine whether additional actions or program enhancements are warranted to ensure assets remain suitable for continued service. DIMP also evaluates emerging threats identified through industry incidents and incorporates relevant lessons learned, best practices, and industry findings into the program. As a result, DIMP helps identify potential gaps in existing O&M programs and supports the implementation of additional measures, where warranted, to further reduce risk.

   Therefore, O&M activities focus on the execution of routine actions necessary to ensure the system is operated safely, reliably, and in compliance with applicable requirements, whereas DIMP uses a risk-informed approach to evaluate system performance, identify areas of elevated risk, and support the continuous improvement of system safety and reliability.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 4, Schedule 3

Preamble:

We would like to understand better the EDIMP program and the associated ratepayer benefits.

Question(s):

For the pipelines named in Table 2, for each project, please provide each of the updates for those projects since 2021 from each updated version of AMP reports.

Response:

The Enbridge Gas Asset Management Plan (AMP) 2025-2034 (published October 31, 2024) and previous versions of the AMP dating back to 2021, do not provide project-specific updates for the five pipelines identified in Exhibit G, Tab 4, Schedule 1, Table 2.

The pipelines identified in Exhibit G, Tab 4, Schedule 1, Table 2 are part of the Enhanced Distribution Integrity Management Program (EDIMP) population described in Section 1.5.1 of the AMP, which consists of distribution steel pipelines exhibiting higher potential risk and criticality relative to the remainder of the steel distribution network.

The first year of EDIMP inspections (2024) included three pipelines that had previously been identified in the AMP as full replacement projects: the NPS 12 Wilson Avenue, NPS 12 Martin Grove, and NPS 8 Port Stanley pipelines.

The preferred alternatives for the NPS 12 Wilson Avenue and NPS 12 Martin Grove are no longer full pipeline replacements in the AMP, as Enbridge Gas will be implementing inspect & repair asset life extension solutions for these pipelines. Enbridge Gas is continuing to evaluate long-term mitigation alternatives for the NPS 8 Port Stanley pipeline and, accordingly, the replacement project remains identified in the AMP at this time. Please see Exhibit G, Tab 4, Schedule 1, pages 15-18, for additional details on these pipelines.

Following inspection and assessment through the EDIMP process, Enbridge Gas evaluates whether the pipeline is fit-for-service and whether alternatives to replacement can reduce risk to tolerable levels. As a result, EDIMP priority pipelines will only be included in future AMP capital plans where inspections, quantitative risk assessments, and the evaluation of mitigation alternatives demonstrate that significant capital investment is the preferred option to address identified risks.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 4, Schedule 3

Preamble:

We would like to understand better the EDIMP program and the associated ratepayer benefits.

Question(s):
For each project listed on page 14 that underwent consultant desktop study, please provide the resulting consultant report including data, findings and recommendations.

a) Please provide the cost of consulting services associated with this work and confirm that the costs are in the EDIMP account.

Response:

Attached to this response is the annual report prepared by BGC Engineering Inc. summarizing the results of the geohazard study and assessments completed for the 2025 Enhanced Distribution Integrity Management Program (EDIMP) inspected pipelines.

a) Please see Exhibit C, Tab 2, Schedule 14, Table 2 for a summary of costs recorded in the EDIMP account. The consulting service costs associated with the geohazard assessments are included in Line No. 12 “Assessments & Consulting” and account for approximately $0.138 million of the $0.233 million reported in that category. These costs are recorded entirely in the EDIMP account.

Geohazard Inspections Report

2025 Annual Inspections for Enbridge GDS EDIMP

Prepared by BGC Engineering Inc. for:

Enbridge Gas Distribution and Storage

October 22, 2026

Project 2008113

October 22, 2026 Project 2008113

Enbridge Gas Distribution and Storage
500 Consumers Road
North York, ON M2J 1P8

Attention: Mr. Arvind Chhabra, P.Eng., Supervisor, EDIMP

2025 Annual Inspections for Enbridge GDS EDIMP

Please find attached the above referenced final report summarizing the geohazard (hydrotechnical and geotechnical) inspections conducted along Enbridge Gas Distribution and Storage's pipelines managed by the Enhanced Distribution Integrity Management Program (EDIMP) in Canada.

This report provides background to the inspections, the results of which are accessible in Cambio™. Enbridge's data are accessible from the online database at **https://cambio.bgcengineering.ca**.

We look forward to your comments and a continuation of the geohazard inspections as part of your ongoing geohazard management program.

Yours sincerely,

BGC Engineering Inc.
per:



John Perry, M.Sc., P.Eng.
Senior Geological Engineer

EXECUTIVE SUMMARY

Since 2019, BGC Engineering Inc. (BGC) has been working with Enbridge Gas Distribution and Storage (Enbridge) to develop a geohazard inventory on their pipelines managed by the Transmission Integrity Management Program (TIMP) in Ontario, Canada. In 2023, Enbridge commenced a geohazard management program (GMP) with BGC, which included Cambio™, for the pipelines managed by the TIMP. Through 2024 and 2025, Enbridge expanded the GMP and Cambio to include pipelines managed by the Enhanced Distribution Integrity Management Program (EDIMP), which has approximately 7,000 km of pipeline in Ontario, Canada. The work completed in 2025 included:

- Uploading Stantec Consulting Ltd.'s (Stantec's) ground inspections between 2019 and 2021 for 12 hydrotechnical hazard sites (the Stantec recommendations were only altered by BGC based on difference in terminology, for example, 'ongoing monitoring' recommended by Stantec was considered as 'continued ground inspections' by BGC)
- Reviewing each site with Enbridge and actioning some recommendations for the 14 geohazard sites with a high (>10^{-3}) probability of failure (PoF) as given in Table E-1.
- Developing geotechnical and hydrotechnical hazard inventories and screening-level assessments for eight EDIMP pipelines, identified by Enbridge, totalling approximately 65 km. This work identified 20 active geotechnical hazard sites and 15 active hydrotechnical hazard sites
- Four BGC ground inspections
- A screening-level vortex-induced vibration (VIV) failure assessment for Cambio Site Identification Number (SID) 5691 (Big Creek)
- One site was identified by Enbridge to be on an abandoned portion of pipeline and therefore made inactive with an office inspection to document the reason.

This report summarizes the ground and office inspections completed under the 2025 GMP and provides recommendations for ongoing geohazard management of these geohazard sites. Information from the inspections is stored in Cambio. The database is located at **https://cambio.bgcengineering.ca** and contains inspection observations, photos, reports, and estimates of the likelihood of pipeline exposure, impact, or failure for each geohazard site as appropriate.

The work above resulted in the estimation of screening-level PoF for each of the active geohazard sites. A course of action has been assigned to each of the geohazard sites identified and reviewed under the scope, and an action timing was recommended in accordance with the estimated annual PoF. The GMP assists with managing and prioritizing geohazard sites for these various actions. The 14 geohazard sites on the EDIMP pipeline system with a probability of failure of greater than 1 x 10^{-3} (i.e., Category 1 and 2 geohazard sites) are summarized in Table E-1.

Table E-1 Summary of the Category 1 and 2 geohazard sites available in Cambio at the end of 2025 on Enbridge's pipelines managed by the EDIMP.

SID	Site Name	Pipeline Name	Probability of Failure	Recommendation[1]
4167	North Sydenham River (4167)	SARNIA NORTH 160 24 20	[redacted]	Stantec recommendation: This site should be considered for remediation for depth of cover (DoC) to comply with CSA Z662-15 standards.
4199	Slope Encroachment (4199)	NPS 36 Mississauga Southern Link	[redacted]	BGC recommendation: Continue ground inspection to observe any changes to the encroaching ground movement hazard and remeasure its distance to the pipeline.
4161	Sydenham River (4161)	SARNIA SOUTH 100 24 03	[redacted]	Stantec recommendation: This site should be considered for remediation for DoC to comply with CSA Z662-15 standards; otherwise, this site should be considered for inspection every year.
4163	Bear Creek (4163)	SARNIA NORTH 160 24 20	[redacted]	Stantec recommendation: This site should be considered for remediation for DoC to comply with CSA Z662-15 standards; otherwise, this site should be considered for inspection every year.
4178	Grand River (4178)	TILLSONBURG 520 74 01	[redacted]	Stantec recommendation: The site should be considered for ongoing monitoring (BGC recommends follow-up ground inspections to remeasure the DoC).
4166	Bear Creek (4166)	SARNIA NORTH 160 24 20	[redacted]	Stantec recommendation: This site should be considered for remediation for DoC to comply with CSA Z662-15 standards; otherwise, this site should be considered for inspection every year.
4169	Kettle Creek (4169)	PORT STANLEY and St Thomas	[redacted]	Stantec recommendation: The site should be considered for an investigation and/or mitigation.
4170	Unnamed Creek (4170)	TILLSONBURG 520 74 01	[redacted]	Stantec recommendation: This site should be considered for remediation for DoC to comply with CSA Z662-15 standards; otherwise, this site should be considered for inspection every year.
4347	Credit River (4347)	Derry Rd and Old Creditview Rd	[redacted]	BGC recommendation: Conduct ground inspections at the sites, obtain the DoCs, and document the locations of the pipelines in relation to flow conveyance infrastructure at the crossings (i.e., culverts). In the interim, obtain as-built information to confirm DoCs and pipeline installation methods.
4285	Credit River (4285)	NPS 20 Queensway	[redacted]	
4309	Little River (4309)	NPS 10 Tecumseh	[redacted]	

SID	Site Name	Pipeline Name	Probability of Failure	Recommendation[1]
3936	Unnamed Creek Exposure (3936)	PORT STANLEY and St Thomas	[redacted]	BGC recommendation: Vortex-induced vibration failure is considered unlikely to occur. However, it is BGC's understanding that Enbridge intends to mitigate the site. In the interim, conduct routine ground inspections to observed whether there has been a change to site conditions.
5716	Unnamed Slope (5716)	NPS 20 Sydenham Rd	[redacted]	BGC recommendation: The pipeline location should be verified either through as-built record drawings, ground inspection, or professional survey. In the interim, Enbridge should consider having inertial measurement unit data collected for the site to further evaluate the geotechnical hazards and potential pipeline impacts. Repeat ground inspections are also recommended to observe any changes to site conditions, particularly with respect to ground movement activity.
3421	Unnamed Stream (3421)	NPS 10 English River Lateral	[redacted]	BGC recommendation: Continue routine ground inspections at the crossing to remeasure the depth of cover and observe changes to the log jam upstream of the bridge.

Note:

1. The recommendations are by either BGC or Stantec depending on the company that completed the last inspection. The Stantec recommendations were only altered by BGC based on difference in terminology, for example, 'ongoing monitoring' recommended by Stantec was considered as 'continued ground inspections' by BGC.

Note that Cambio is dynamic and any updates to these geohazard sites may have occurred after this report was issued. Therefore, refer to Cambio for the most up-to-date and relevant details for each geohazard site beyond the date of this report. All data presented in this report are based on Cambio data available up to December 31, 2025.

LIMITATIONS

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[1] References in these Limitations to the “document” include the document to which these Limitations are attached, any content contained in this document, and any content referenced in this document but located in one of BGC’s proprietary software applications (e.g., Cambio).

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1.0 INTRODUCTION

This geohazard inspections report provides a summary of the office and ground inspections completed in 2025 for the geohazard sites relating to Enbridge Gas Distribution and Storage's (Enbridge) pipelines managed by the Enhanced Distribution Integrity Management Program (EDIMP).

Enbridge can refer to BGC Engineering Inc.'s (BGC's) Method Documents (seven documents by BGC, January 26, 2026a-g, as listed in the References) for definitions of technical terms and further details of the methodologies and assessments described below.

1.1 Background

The purpose of a GMP is to develop and maintain an inventory of hydrotechnical (watercourse), geotechnical (slope), and seismic hazard sites and implement a schedule of actions to manage the annual probability of pipeline exposure/impact and loss of containment from geohazards. These actions include desktop and field inspections, detailed investigations, maintenance, surveys, and mitigations. Enbridge's geohazard site locations and inspection results are stored in an online geohazard management software platform, Cambio™[2]. The geohazards inventory and inspection program, along with geohazard management tools such as flood and precipitation monitoring lay the groundwork for a corporate risk management plan, but in themselves do not constitute risk assessment or risk management.

1.2 Program History

In 2024, BGC commenced a GMP with Enbridge for pipelines managed by the EDIMP. This work included tasks such as:

- Cambio development of workspaces to easily navigate and filter between views and systems within Enbridge
- Uploading over 7,000 km of linework for the EDIMP pipelines to Cambio
- Adding approximately 25 historical Stantec ground inspections[3] to Cambio
- Completing geotechnical and hydrotechnical hazard inventories and screening-level assessments for select pipelines totalling approximately 300 km
- Completing ground inspections.

[2] Cambio™ is a cloud-hosted software platform developed by BGC and Cambio Earth Systems Inc. (BGC's software entity) to manage geohazards. The platform organizes the identified geohazard sites spatially and enables the user to prioritize them for future action, build inspection, monitoring and maintenance programs, and store site history. Enbridge is a subscriber to Cambio and uses the software as part of their overall integrity management program for their operating pipelines.

[3] Stantec Consulting Ltd. (Stantec) completed over 1,000 ground inspections between 2018 and 2022 for Enbridge's GDS pipelines, some of which were for the EDIMP. Only approximately 25 of these historical Stantec ground inspections for the EDIMP were available in Cambio at the end of 2024.

1.3 Definitions

1.3.1 Recommended Actions

The annual probability of failure (PoF) of a pipeline because of a geohazard is used to guide the timing for the recommended next action, in accordance with Figures A-1 and A-2 (Appendix A) for geotechnical and hydrotechnical hazards, respectively. A list of recommended actions is provided in Table A-3 (Appendix A). The screening-level estimates of annual probability of exposure (PoE) and annual probability of impact (PoI), and pipeline vulnerability may be refined as part of detailed investigations, as needed. The definitions of vulnerability, PoE, PoI, and PoF are available in the Geotechnical and Hydrotechnical Screening-Level Method Documents (BGC, January 26, 2026c,d).

1.3.2 Inactive Geohazard Sites

Inactive geohazard sites are possible geohazard sites that have since been confirmed through field verification or lidar review to pose no or only a negligible hazard to the pipeline. An inspection is added to Cambio to record the information reviewed and change from active to inactive, and the geohazard site is removed from the inventory of active geohazard sites. These inactive geohazard sites are not scheduled for active management or associated action timings (i.e., will not form part of the future implementation of the GMP unless they are made active again). Inactive sites are searchable in Cambio by selecting ‘All’ (i.e., active and inactive) during Cambio queries.

1.4 Terms of Reference

BGC was retained by Enbridge to complete the 2025 GMP for Enbridge’s pipelines managed by the EDIMP under Standard Purchase Orders 76241 and 79303 dated January 20 and October 24, 2025, respectively.

The services provided during this assignment are governed by the Master Engineering Services Agreement (the “Agreement”) between Enbridge Employee Services Canada Inc. and BGC. The Agreement is identified as Oracle/Ariba Contract Nos. 50014/ CW2247766 / CW2247768, and it became effective September 30, 2021. All use of BGC’s Cambio software platform or other BGC-owned databases or software will be governed by the License Terms and Conditions attached to the Agreement as Exhibit E.

2.0 SCOPE OF WORK

This report covers the work scope in the GMP proposal (BGC, October 24, 2024) but does not discuss the project management that was outlined in the GMP proposal.

There were changes to the scope as given in the sections below. The main scope changes included the addition of:

- Ground inspections at four geohazard sites Cambio Site Identifiers (SIDs) 4270, 4363, 5691, and 5716.
- An office inspection in Cambio at SID 4261 to make it inactive given the pipeline was abandoned.
- A screening-level vortex-induced vibration (VIV) failure assessment at SID 5691.

2.1 Geohazard Inventory and Screening-level Assessment

The proposal (BGC, October 24, 2024) included the completion of a geotechnical and hydrotechnical hazard inventory and screening-level assessment for approximately 200 km of pipeline managed by the EDIMP. The pipeline locations and names were not available at the time of the proposal, but were confirmed to BGC by Enbridge on January 14 (during a progress meeting) and April 22 (via email), 2025 and these are given in Table 2-1.

Table 2-1 The EDIMP pipelines captured in the geohazard inventory and screening-level assessment scope.

Pipeline Name in Cambio	Approximate Length (km)
St. Laurent	11
NPS 6 Dryden	3
NPS 10 Bentpath	6
NPS 12 Effingham	5
NPS 12 Third Concession Rd	9
NPS 16 Sheppard Ave E	1
NPS 20 Sydenham Rd	10
Atikokan	20
NPS 36 Mississauga Southern Link[1]	23
NPS 10 English River Lateral[1]	77
TOTAL	165

Note:

1. Both the NPS 36 Mississauga Southern Link and NPS 10 English River Lateral pipelines are currently managed by Enbridge's Transmission Integrity Management Program (TIMP), but will soon be transferring to management under the EDIMP. During their management under the TIMP, geohazard work by BGC and Stantec was completed.

2.2 Historical Stantec Ground Inspections

Stantec completed over 1,000 ground inspections between 2018 and 2022 at hydrotechnical hazard sites on pipelines managed by Enbridge. The proposal (BGC, October 24, 2024)

included adding historical Stantec ground inspections for approximately 200 km of pipeline managed by the EDIMP, but the pipeline names and locations were not confirmed at the time of writing the proposal. Therefore, BGC had assumed there would be approximately 15 historical Stantec ground inspections for the 200 km of pipeline.

As mentioned in Section 2.1 and given in Table 2-1, the pipeline locations and names were confirmed to BGC by Enbridge in early to mid-2025, which Enbridge did not identify any historical Stantec ground inspections that were not already in Cambio on these lines. However, Enbridge requested historical Stantec ground inspections on other pipelines to be uploaded to Cambio. It was agreed with Enbridge via email on July 4, 2025, that three historical Stantec ground inspections were to be entered in full to Cambio, so the screening-level vulnerability and PoE were calculated, which resulted in a screening-level PoF. Enbridge confirmed in the same correspondence that eight historical Stantec ground inspections were to be uploaded as photo inspections to Cambio, which does not calculate screening-level vulnerability, PoE or PoF, given these were inactive hydrotechnical hazard sites. An additional historical Stantec ground inspection (Big Creek (5691)) was requested by Enbridge on July 29, 2025, to be included in the scope to calculate screening-level vulnerability, PoE or PoF.

3.0 GEOHAZARD INVENTORY AND SCREENING-LEVEL ASSESSMENTS

The following sections outline the approach to geohazard inventory and screening-level assessments for geotechnical and hydrotechnical hazards. Further details for the methodologies are available in the Geotechnical and Hydrotechnical Screening-Level Method Documents (BGC, January 26, 2026c,d).

The NPS 36 Mississauga Southern Link and NPS 10 English River Lateral pipelines that previously had their work completed under separate scopes with the TIMP were not re-assessed, but their results are given in Section 6.0. Therefore, only eight EDIMP pipelines were assessed in Sections 3.1 and 3.2.

3.1 Geotechnical Hazard Inventory and Screening-Level Assessment

Geotechnical hazards considered in the geotechnical hazard site inventory and screening-level assessment included ground movement hazards such as debris, earth, and rockslides, rock fall, and earth creep, and erosional hazards such as gullying. In the context of this work, geotechnical hazards excluded glaciomarine clay hazards, seismic hazards, subsidence hazards, or interaction with anthropogenic features (e.g., earthworks and adjacent infrastructure).

3.1.1 Methodology



[redacted]

3.1.2 Results and Recommendations

A total of 20 (20 active and no inactive) geotechnical hazard sites were identified on the eight EDIMP pipelines and screening-level assessments were completed for the 20 active geotechnical hazard sites to estimate a screening-level PoF. The results are presented in Appendix B and summarized in Table 3-1.

Table 3-1 A summary of the geotechnical hazard sites identified during the geohazard inventory and screening-level assessments.

Hazard Category (Rating)	PoF	Timing	Site Count
Category 1 (Very High)	$1x10^{-2}$ to 1	< 1 year	0
Category 2 (High)	$1x10^{-3}$ to $1x10^{-2}$	< 1 year	1
Category 3 (Medium)	$1x10^{-4}$ to $1x10^{-3}$	< 2 to 5 years	0
Category 4 (Low)	$1x10^{-5}$ to $1x10^{-4}$	< 4 to 8 years	4
Category 5 (Very Low)	$<1x10^{-5}$	< 9 years	15
Inactive	Not applicable	Not applicable	0
		TOTAL	20

Five (5) active geotechnical hazard sites were recommended for ground inspection to observe and document site conditions (e.g., evidence of ground movement and erosion hazards) and potential drivers for instability (e.g., toe erosion, surface water runoff, etc.). In particular, the pipeline at SID 5716, which was a Category 2 site as defined by Appendix A, was observed to cross 380 m of landslide morphology, so was recommended for a ground inspection that was completed within 2025 (refer to Section 5.0). The remaining 15 active geotechnical hazard sites were recommended for office inspections as no landslide morphology was observed in the lidar, but the slope met the geometric criteria given in Section 3.1.1.

No geotechnical hazard sites were identified on the NPS 16 Sheppard Ave E, NPS 12 Third Concession, NPS 12 Effingham St, or St. Laurent Pipelines.

3.2 Hydrotechnical Hazard Inventory and Screening-Level Assessment

3.2.1 Methodology

[redacted]

Flood Frequency Analysis

[redacted]

[redacted]

[redacted]

Probability of Exposure

[redacted]

Screening-level Hydrotechnical Vulnerability and PoF

[redacted]

3.2.2 Results and Recommendations

A total of 49 (15 active and 34 inactive) hydrotechnical hazard sites were identified on the eight EDIMP pipelines and screening-level assessments were completed for the 15 active hydrotechnical hazard sites to estimate a screening-level PoF. All hydrotechnical hazard sites and their screening-level PoFs are presented in Appendix B and summarized in Table 3-2. There were no Category 1 and 2 hydrotechnical hazard sites, as defined by Appendix A.

Table 3-2 A summary of the hydrotechnical hazard sites identified.

Hazard Category (Rating)	PoF	Timing	Site Count
Category 1 (Very High)	$1x10^{-2}$ to 1	< 1 year	0
Category 2 (High)	$1x10^{-3}$ to $1x10^{-2}$	< 1 year	0
Category 3 (Medium)	$1x10^{-4}$ to $1x10^{-3}$	< 2 to 5 years	2
Category 4 (Low)	$1x10^{-5}$ to $1x10^{-4}$	< 4 to 8 years	3
Category 5 (Very Low)	$1x10^{-6}$ to $1x10^{-5}$	< 9 years	4
Category 6 (Extremely Low)	$<1x10^{-6}$ (Hydrotechnical)	Inspect on trigger	6
Inactive	Not applicable	Not applicable	34
		TOTAL	**49**

A total of 34 hydrotechnical hazard sites were not considered to pose an integrity threat to a pipeline due to their small catchment area and/or bankfull width and were made inactive. A photo inspection was added to Cambio to document its entry, and record that it was made inactive in Cambio. A screening-level PoF was not calculated for these hydrotechnical hazard sites.

Of the 15 active hydrotechnical hazard sites, 12 were watercourse crossings and three were watercourse encroachments. Two sites (SIDs 4542 and 5729) were recommended for a survey, and one (SID 5761) was recommended for an office inspection to obtain as-built drawings. The remaining 12 sites were recommended for a ground inspection. All these recommendations are to obtain the DoC, capture other channel characteristics (e.g., bank erosion, slumping, scour holes, etc.), and document the location of the pipeline in relation to flow conveyance infrastructure at the crossing (e.g., culverts). While these ground inspection observations are necessary to refine the screening-level PoF to a more accurate estimate, Enbridge may have as-built information available at these hydrotechnical hazard sites that could confirm the DoC and pipeline installation method, which can also refine the screening-level PoF.

No hydrotechnical hazard sites were identified on the NPS 16 Sheppard Ave E Pipeline.

4.0 HISTORICAL STANTEC GROUND INSPECTIONS

4.1 Methodology

[redacted]

4.2 Results

A total of 12 hydrotechnical hazard sites were added to Cambio to capture the 12 historical Stantec ground inspections as given in Section 2.2. The screening-level PoFs and recommendations for the four active hydrotechnical hazard sites based on the historical Stantec ground inspection data are summarized in Table 4-1 and can be found in Appendix C. Three of the four sites (SIDs 4270, 4363, and 5691) had a BGC ground inspection completed within 2025 (refer to Section 5.0), so the screening-level PoF and recommendations by Stantec were superseded by the BGC ground inspection. The remaining site (SID 4263) was an aerial crossing that was recommended by BGC for a ground inspection in the future to observe whether conditions have changed.

Table 4-1 Historical Stantec ground inspection uploads to Cambio during 2025.

SID	Site Name	Pipeline Name	Min. DoC (m)	Bankfull Width/Slope Length (m)	Stantec Recommendations	PoF
5691[1]	Big Creek (5691)	TILBURY NORTH 600 02 05	0.0	63	As per the DoC Action Scale provided by Enbridge Gas Inc, with an observed DoC at the site of 0 m (exposed), the watercourse crossing should be considered for an investigation and/or mitigation (Stantec, July 7, 2021).	[redacted]
4270[1]	Unnamed Stream Aerial Crossing (4270)	SARNIA SOUTH 100 24 03	0.0	5.7	This site is ranked as H0, very high priority. This site should be considered for remediation for DOC to comply with CSA Z662-15 standards (Stantec, February 11, 2020).	[redacted]
4263	Unnamed Stream Aerial Crossing (4263)	SARNIA SOUTH 100 24 03	-[2]	8.5	No recommendation was given by Stantec, so BGC recommends continuing ground inspections to observe whether there have been any changes to site conditions (Stantec, May 5, 2021).	[redacted]
4363[1]	Unnamed Creek Aerial Crossing (4363)	PORT STANLEY and St Thomas	-[2]	4	No recommendation was given by Stantec, so BGC recommends continuing ground inspections to observe whether there have been any changes to site conditions (Stantec, May 31, 2021).	[redacted]

Notes:

1. SIDs 4270, 4363, and 5691 had BGC ground inspections completed within 2025 (refer to Section 5.0), so the screening-level PoF and recommendations by Stantec were later updated by the BGC ground inspection.
2. The PoF is based on vulnerability as these sites are aerial crossings well above the 2-year flow, so they are without a DoC measurement to calculate PoE and subsequently PoF.

5.0 GROUND INSPECTIONS

5.1 Methodology

5.1.1 Field Reconnaissance

[redacted]

5.1.2 Data Compilation

[redacted]

5.2 Summary of the 2025 Ground Inspections

The inspected hydrotechnical and geotechnical hazard sites have been assigned a recommended action as per Table A-1 and an action timing in accordance with Figures A-1 and A-2 (Appendix A).

Due to the number and dynamic nature of the geohazard sites, the reader is directed to Cambio for the most up-to-date geohazard information. For Enbridge's convenience, a summary of the geohazard sites that were inspected in 2025 is provided in Table 5-1. Further site-specific details, recommendations, and photographs for each inspection can be found in Cambio.

Table 5-1 2025 ground inspections summary.

SID	Site Name	Pipeline Name	Hazard Type	Min. DoC (m)	Bankfull Width/Slope Length (m)	Comments and Recommendation	PoF
5716	Unnamed Slope (5716)	NPS 20 Sydenham Rd	Geotechnical	1.7	305	The pipeline crosses a landslide. However, access to the north of the railway was not available meaning the pipeline location could not be confirmed and the upper portions of the landslide could not be inspected. The pipeline location should be verified either through as-builts records, survey, or by ground inspection with access to the north of the railway. In the interim, Enbridge may consider having inertial measurement unit (IMU) data collected for the site to further evaluate the geotechnical hazards and potential pipeline impacts.	[redacted]
5691	Big Creek (5691)	TILBURY NORTH 600 02 05	Hydrotechnical	0.0	63	The pipeline is exposed and spanning for a total of 4.1 m and bank erosion was observed that could increase the span length. Continue ground inspections to monitor any further bank erosion and increase to the span length. Further details on this site are provided in Section 7.0.	[redacted]
4363	Unnamed Creek Aerial Crossing (4363)	PORT STANLEY and St Thomas	Hydrotechnical	-[1]	7.5	The pipeline at this site spans across the channel. No flow was observed in the channel at the time of inspection. However, trees were observed that may pose a hazard of falling onto the pipeline. Continue ground inspections to observe any changes to site conditions. In the interim, Enbridge may consider assessing whether tree removal close to the pipeline is necessary.	[redacted]

SID	Site Name	Pipeline Name	Hazard Type	Min. DoC (m)	Bankfull Width/Slope Length (m)	Comments and Recommendation	PoF
4270	Unnamed Stream Aerial Crossing (4270)	SARNIA SOUTH 100 24 03	Hydrotechnical	-[1]	5.7	The pipeline at this site spans across the channel bed. No water flow was present in the channel, and there were no clear indications of previous flow activity. Continue ground inspections to observe any changes to site conditions.	[redacted]

Note:

1. The PoF is based on vulnerability as these sites are aerial crossings well above the 2-year flow, so they are without a DoC measurement to calculate PoE and subsequently PoF.

6.0 PIPELINES CHANGING MANAGEMENT FROM THE TIMP TO THE EDIMP

The NPS 36 Mississauga Southern Link and NPS 10 English River Lateral pipelines previously had their work completed under separate scopes with the TIMP. These two pipelines are or will be under the EDIMP's management. The various assessments completed on these two pipelines for the TIMP are given in several BGC reports (BGC, December 6, 2019, April 14, 2021, May 17, 2023, and March 6 and August 18, 2025), which also include a seismic and glaciomarine hazard assessment (BGC, September 2, 2025). Site-specific details and recommendations can be found in Cambio.

Table 6-1 summarizes the number of geohazard sites on the two pipelines. The latest active geohazard sites are presented in Appendix D and the two geohazard sites with a probability of failure of greater than 1 x 10^{-3} (i.e., Category 2 geohazard sites. Note that there were no Category 1 geohazard sites.) are summarized in Table 6-2.

Table 6-1 Summary of the geohazard sites available in Cambio at the end of 2025 on the NPS 36 Mississauga Southern Link and NPS 10 English River Lateral Pipelines.

Hazard Category (Rating)	PoF	Timing	Site Count	
			NPS 36 Mississauga Southern Link Pipeline	NPS 10 English River Lateral Pipeline
Category 1 (Very High)	$1x10^{-2}$ to 1	< 1 year	0	0
Category 2 (High)	$1x10^{-3}$ to $1x10^{-2}$	< 1 year	1	1
Category 3 (Medium)	$1x10^{-4}$ to $1x10^{-3}$	< 2 to 5 years	1	4
Category 4 (Low)	$1x10^{-5}$ to $1x10^{-4}$	< 4 to 8 years	0	11
Category 5 (Very Low)	$<1x10^{-5}$ (Geotechnical) / $1x10^{-6}$ to $1x10^{-5}$ (Hydrotechnical)	< 9 years	7	4
Category 6 (Extremely Low)	$<1x10^{-6}$	Inspect on trigger	0	7
Vulnerability Only[1]	-	Various	0	26
Inactive	Not applicable	Not applicable	20	27
Seismic[2]	Not applicable	Not applicable	5	67
		TOTAL	34	147

Notes:

1. The screening-level PoF is based on vulnerability only as the site has low resolution lidar where ground movement and erosion hazards are difficult to observe.
2. Seismic hazard sites are for monitoring purposes only and do not have a screening-level PoF or timing associated with them.

Table 6-2 Summary of the Category 2 geohazard sites available in Cambio at the end of 2025 on the NPS 36 Mississauga Southern Link and NPS 10 English River Lateral pipelines.

SID	Site Name	Pipeline Name	Hazard Type	Min. DoC (m)	Bankfull Width/Slope Length (m)	Comments and Recommendation	PoF
4199	Slope Encroachment (4199)	NPS 36 Mississauga Southern Link	Geotechnical	1.5	40	Continue ground inspection to observe any changes to the encroaching GMH. Remeasure the monitoring pin to trail edge at the closest point of encroachment. Remeasure closest distance from monitoring pin to pipeline centreline and make observations of recent slope failure and erosion. Review historical and future lidar and aerial imagery to assess rates of retrogression. In the interim, contact Enbridge to find details on the slope inclinometers at the slope crest and review data if available. These steps would likely include: - Working with Enbridge to determine the owner of the slope inclinometers. - Reviewing historical and future lidar and aerial imagery to assess rates of retrogression. - Understanding the allowable span length should retrogression occur. [An assessment was done at the site for Enbridge Liquids Pipelines, which is closer to the hazard than the EDIMP pipeline, that updated the screening-level PoF and recommendations. These results will be leveraged for the NPS 36 Mississauga Southern Link Pipeline during 2026.]	[redacted]
3421	Unnamed Stream (3421)	NPS 10 English River Lateral	Hydrotechnical	0.4	15	Continue routine ground inspections at the crossing to monitor for changes in the DoC and any blockage due to log jam upstream of the bridge/where the drop located.	[redacted]

7.0 BIG CREEK (5691)

7.1 Historical Stantec Ground Inspection

A ground inspection was completed by Stantec on April 24, 2021, which is captured in Section 4.0. Stantec observed the pipeline to be spanning and that bank erosion had occurred on the right (inside / east) bank. Stantec recommended that the watercourse crossing should be considered for an investigation and/or mitigation.

7.2 Enbridge Ground Inspection

Enbridge staff completed an inspection of the site in July 2025 and observed that accelerated bank erosion had taken place on the right bank. Enbridge recommended BGC to complete a ground inspection and screening-level VIV assessment in parallel.

7.3 BGC Ground Inspection

A ground inspection was completed by BGC on September 14, 2025, which noted that there had been approximately 0.4 m of bank erosion on the right bank since the April 24, 2021, Stantec ground inspection. Monitoring points were established on the site to allow measurements of bank erosion in the future by the use of a measuring tape. While the watercourse was too deep to wade, the water appeared stagnant with little to no flow.

It was suspected that the recent erosion observed in the field may have been associated with the collapse of the previously unsupported bank segment (i.e., 0.4 m undercut section) observed in 2021.

Further site-specific details, recommendations, and photographs for the ground inspection can be found in Cambio.

7.4 Screening-level VIV failure Assessment

A screening-level historical aerial imagery review was conducted in Google Earth to review the channel bank alignment near the Big Creek crossing. No large-scale geomorphic changes indicative of long-term meander migration between 1954 and 2022 were observed. The recent changes observed in the Enbridge and BGC ground inspections were likely due to minor erosion. No flow events exceeding the 25-year flood were observed at nearby hydrometric gauges from April 2021 (i.e., Stantec's ground inspection) to present, indicating that there were no recorded events that would likely cause large bank erosion.

As mentioned in Section 7.3, the recent erosion observed in the field may have been due to the unsupported bank falling into the watercourse. This erosion appeared to be the result of ongoing minor bank erosion rather than a major shift in bank location.

During the 2025 BGC ground inspection, the channel could not be waded. However, measurements of the pipeline along the right bank, along with the 2021 pipe and ground profile collected by Stantec, indicated that the pipeline was exposed and spanning for 2.6 m along the

right bank and not along the channel bed. An additional 1.5 m of pipeline is unsupported under the bank top but remained covered by soil.

The VIV assessment considered the further development of a span along the right bank of the channel due to bank erosion. Given the pipe profile, it was assumed that the maximum span length that could develop under those conditions was 6 m to 7 m. Based on the screening-level VIV assessment, the pipeline was not expected to develop a span length required for VIV initiation under the estimated 2- to 500-year flood scenarios.

7.5 Conclusions and Recommendations

Bank erosion was suspected to have been minor since 1954, and the recent bank erosion was due to the failure of an unsupported section of soil on the right bank, rather than due to flood conditions. The screening-level PoF was estimated to be [redacted] The pipeline was not anticipated to be susceptible to VIV failure under the estimated 2- to 500-year flood scenarios, so it was recommended for the site to have future ground inspections to observe and measure any changes to site conditions.

8.0 OFFICE INSPECTIONS/DESK STUDY

One site (Thames River (4261)) was identified by Enbridge to be on an abandoned portion of the Sarnia South Pipeline. Therefore, the hydrotechnical hazard site was made inactive and a photo inspection was added to document the reason.

9.0 CONCLUSIONS AND CONSIDERATIONS FOR FUTURE WORKS

BGC added 12 historical Stantec ground inspections for the EDIMP's pipelines in Cambio and identified 35 (20 geotechnical, 15 hydrotechnical) active geohazard sites along the eight EDIMP pipelines requested by Enbridge during the geohazard inventory. BGC completed a Cambio inspection form for each geotechnical and hydrotechnical hazard site in the inventory. The forms captured site characteristics, pipeline properties, and the conditions of the site observed in lidar, satellite imagery, and/or from the historical Stantec ground inspection, and documented screening-level PoE or PoI, and vulnerability estimates to estimate a screening-level PoF for each geohazard site.

Ground inspections were completed by BGC at four geohazard sites. Unnamed Slope (5716) has uncertainty given the pipeline location and access constraints to the upper portion of the slope. It is recommended that the pipeline location be verified either through as-builts, survey, or by ground inspection with access to the north of the railway. In the interim, Enbridge may consider having IMU data collected for the site to further evaluate the geotechnical hazards and potential pipeline impacts.

Following the work completed to date, BGC recommends that Enbridge consider future refinement of the screening-level PoF by completing surveys, ground inspections, or review of additional supporting data as given in Cambio. It is recommended to prioritize work on the Category 1 and 2 geohazard sites as given in Table 9-1.

Table 9-1 Summary of the Category 1 and 2 geohazard sites available in Cambio at the end of 2025 on Enbridge's pipelines managed by the EDIMP.

SID	Site Name	Pipeline Name	Probability of Failure	Recommendation
4167	North Sydenham River (4167)	SARNIA NORTH 160 24 20	[redacted]	Stantec recommendation: This site should be considered for remediation for depth of cover (DoC) to comply with CSA Z662-15 standards.
4199	Slope Encroachment (4199)	NPS 36 Mississauga Southern Link	[redacted]	BGC recommendation: Continue ground inspection to observe any changes to the encroaching ground movement hazard and remeasure its distance to the pipeline.
4161	Sydenham River (4161)	SARNIA SOUTH 100 24 03	[redacted]	Stantec recommendation: This site should be considered for remediation for DoC to comply with CSA Z662-15 standards; otherwise, this site should be considered for inspection every year.
4163	Bear Creek (4163)	SARNIA NORTH 160 24 20	[redacted]	Stantec recommendation: This site should be considered for remediation for DoC to comply with CSA Z662-15 standards; otherwise, this site should be considered for inspection every year.

SID	Site Name	Pipeline Name	Probability of Failure	Recommendation
4178	Grand River (4178)	TILLSONBURG 520 74 01	[redacted]	Stantec recommendation: The site should be considered for ongoing monitoring (BGC recommends follow-up ground inspections to remeasure the DoC).
4166	Bear Creek (4166)	SARNIA NORTH 160 24 20	[redacted]	Stantec recommendation: This site should be considered for remediation for DoC to comply with CSA Z662-15 standards; otherwise, this site should be considered for inspection every year.
4169	Kettle Creek (4169)	PORT STANLEY and St Thomas	[redacted]	Stantec recommendation: The site should be considered for an investigation and/or mitigation.
4170	Unnamed Creek (4170)	TILLSONBURG 520 74 01	[redacted]	Stantec recommendation: This site should be considered for remediation for DoC to comply with CSA Z662-15 standards; otherwise, this site should be considered for inspection every year.
4347	Credit River (4347)	Derry Rd and Old Creditview Rd	[redacted]	BGC recommendation: Conduct ground inspections at the sites, obtain the DoCs, and document the locations of the pipelines in relation to flow conveyance infrastructure at the crossings (i.e., culverts). In the interim, obtain as-built information to confirm DoCs and pipeline installation methods.
4285	Credit River (4285)	NPS 20 Queensway	[redacted]	
4309	Little River (4309)	NPS 10 Tecumseh	[redacted]	
3936	Unnamed Creek Exposure (3936)	PORT STANLEY and St Thomas	[redacted]	BGC recommendation: Vortex-induced vibration failure is considered unlikely to occur. However, it is BGC's understanding that Enbridge intends to mitigate the site. In the interim, conduct routine ground inspections to observed whether there has been a change to site conditions.
5716	Unnamed Slope (5716)	NPS 20 Sydenham Rd	[redacted]	BGC recommendation: The pipeline location should be verified either through as-built record drawings, ground inspection, or professional survey. In the interim, Enbridge should consider having inertial measurement unit data collected for the site to further evaluate the geotechnical hazards and potential pipeline impacts. Repeat ground inspections are also recommended to observe any changes to site conditions, particularly with respect to ground movement activity.

SID	Site Name	Pipeline Name	Probability of Failure	Recommendation
3421	Unnamed Stream (3421)	NPS 10 English River Lateral	[redacted]	BGC recommendation: Continue routine ground inspections at the crossing to remeasure the depth of cover and observe changes to the log jam upstream of the bridge.

Note:

1. The recommendations are by either BGC or Stantec depending on the company that completed the last inspection. The Stantec recommendations were only altered by BGC based on difference in terminology, for example, 'ongoing monitoring' recommended by Stantec was considered as 'continued ground inspections' by BGC.

A ground inspection and screening-level VIV assessment was completed at Big Creek (5691). It is recommended that future ground inspections to observe and measure changes to site conditions are completed given it was not susceptible to VIV failure under the estimated 2- to 500-year flood scenarios.

Additional considerations for future GMPs on pipelines managed by the EDIMP include:

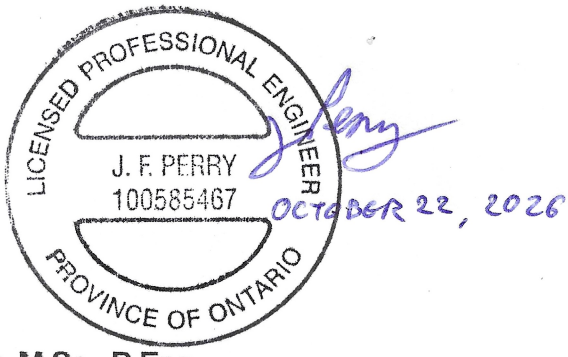
- A review of the historical Stantec ground inspections in Cambio that were recommended by Stantec for detailed investigation or mitigation, and amend the recommendations, where appropriate, to align with the current screening-level PoF of the sites and the current intent of the GMP.
- A seismic and glaciomarine clay hazard assessment.
- Flood and precipitation monitoring through Cambio, similar to what is currently implemented for pipelines managed by the TIMP. Further details of the flood and precipitation monitoring can be found in the Method Document (BGC, January 26, 2026g).
- Geohazard inventory and screening-level assessments for the remaining pipelines by prioritizing the pipelines based on consequence and known geohazard concerns.

10.0 CLOSURE

We trust the above satisfies your requirements. Should you have any questions or comments, please do not hesitate to contact us.

Yours sincerely,

BGC Engineering Inc.
per:



John Perry, M.Sc., P.Eng.
Senior Geological Engineer

Reviewed by:

Martin Devonald, M.Sc.
Principal Consultant

JP/MD/kj/sjk

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APPENDIX A
ACTION TIMING

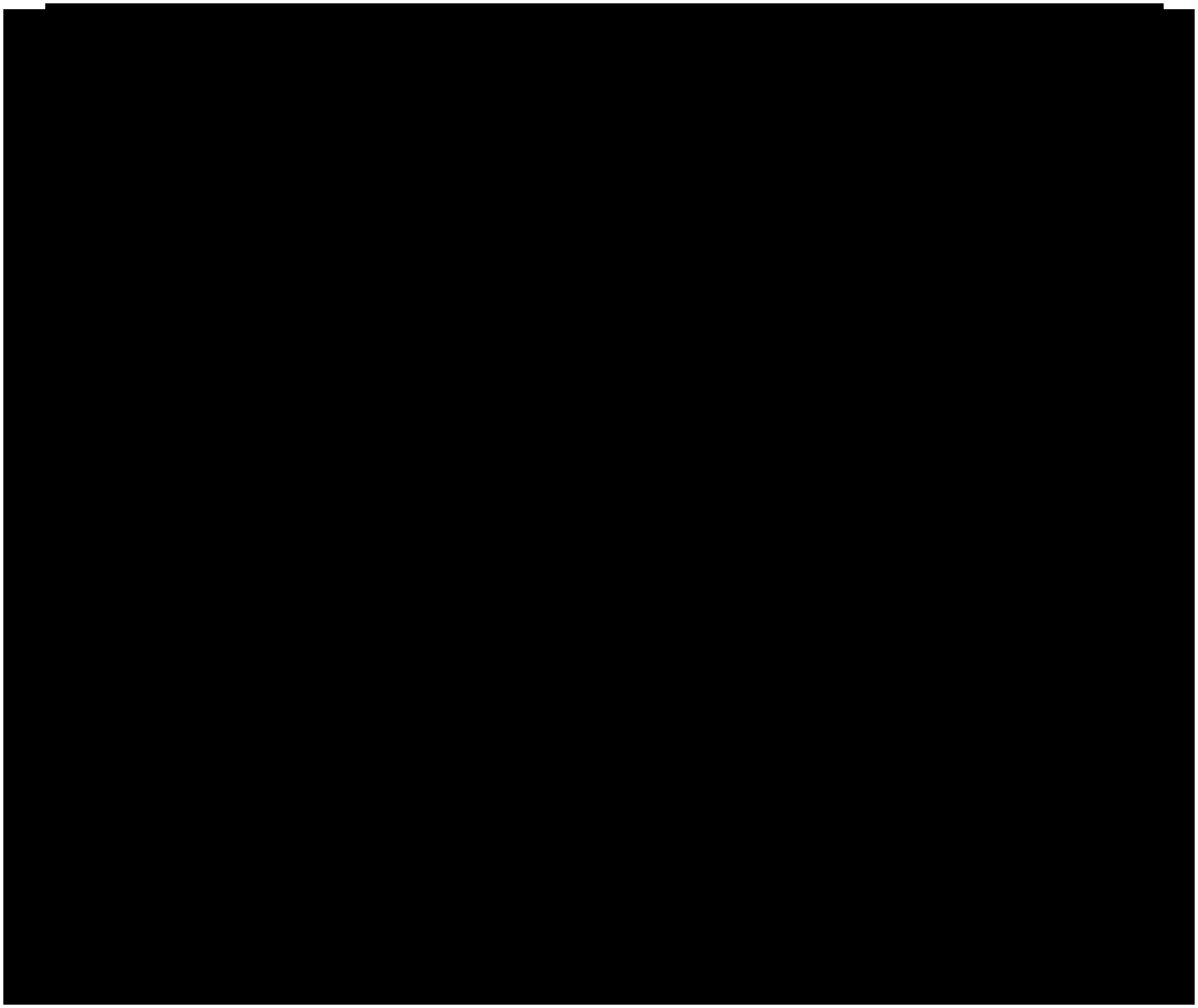




Table A-1 Recommended actions.

Recommended Action	Description
Inspection – Ground	Site visit on foot to subjectively (re-)assess the geohazard activity, the effectiveness of the protection around the pipeline, and to provide new or revised conceptual recommendations.
Inspection – Aerial	Site visit by air to subjectively (re-)assess the geohazard activity and to provide new or revised conceptual level recommendations. The effectiveness of the protection around the pipeline can be assessed if the helicopter lands at the site and a pipe locator is used.
Inspection – Office	An office-based task that typically involves inactivating a site, obtaining and reviewing additional documentation, or conducting a simple desktop analysis to complement an action that has already taken place, such as ground inspection or mitigation. More in-depth office inspections typically occur during detailed investigations.
Detailed Investigation	Intensive site-specific investigation to gather more detailed information such as site surveys to determine DoC, stream morphology, pipe location, geotechnical drilling or hand augering to obtain subsurface information, in-line instrument surveys with calipers and inertial measurement unit (IMU) or office-based time-series air photo interpretation. Detailed investigations are typically not performed unless they are preceded by a ground inspection. Sites are recommended for detailed investigations based on consideration of flow depths, flow velocities and bankfull width at the crossing during a ground inspection. Detailed investigations require several days to complete per site and typically include DoC surveys at watercourses that are followed by a hydrotechnical scour analysis.
Survey	DoC and topographic survey that may include plan bathymetry to facilitate follow-up analyses.
Monitoring	Installation, reading and analysis of surface or subsurface instrumentation to quantify the progression of a geohazard and/or its impact on the pipeline. Examples include reading and analysis of inclinometer data, pipeline strain gauge data, or repeat surveys at a network of ground movement survey hubs.
Maintenance	General field actions typically not requiring an engineering design or significant input from the operator's engineering department. Maintenance activities can be carried out independently by pipeline districts but may require supervision by a technical specialist. Examples of maintenance include cleaning culverts, minor ditch or berm construction, replacement of swamp weights or pipeline markers, culvert installation, and access road maintenance/blocking.
Mitigation	General field actions typically requiring an engineering design or significant input from the operator's engineering department such as riprap placement, slope erosion control, slope drainage control, slope stabilization, or relocation of pipeline. Construction may be preceded with a detailed investigation and an engineered design.

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APPENDIX B
GEOHAZARD INVENTORY AND SCREENING-LEVEL ASSESSMENTS (EXCEL)

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APPENDIX C
HISTORICAL STANTEC GROUND INSPECTIONS (EXCEL)

APPENDIX D
ACTIVE GEOHAZARD SITES ON THE NPS 36 MISSISSAUGA SOUTHERN LINK AND NPS 10 ENGLISH RIVER LATERAL PIPELINES (EXCEL)

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 4, Schedule 3

Preamble:

We would like to understand better the EDIMP program and the associated ratepayer benefits.

Question(s):

For each of the five pipelines within the EDIMP portfolio, please provide:

a) the determination of the NPV's for the respective alternatives including all assumptions (e.g., how long will the pipe be maintained/extended) associated with the Asset Life Extension.
b) the respective QRA reports
c) what EGI has learned about the opportunities for further Asset Life Extension for pipes that would be in the same class (condition, age, soil, etc.).

Response:

a) A Net Present Value (NPV) analysis was conducted for two of the five pipelines selected for in-line inspection in 2024: the NPS 12 Wilson Avenue pipeline and the NPS 12 Martin Grove pipeline. Tables 1 and 2 provide details of the respective NPV analyses.

Table 1.
NPV Results for NPS 12 Wilson Avenue Pipeline Long-term Mitigation Alternatives

NPS 12 Wilson Avenue: NPV Summary ($000's)

Line No.	Particulars	Replacement Option	Inspect & Repair Option
	Cost Elements (Escalated)	2025 to 2084	
1	Net Operating Cash Flow	($5,743)	($55,514)
2	Total Capital	($127,465)	($83,501)
3	CCA Tax Shield	$32,726	$18,178
	Net Present Value (NPV)		
4	PV of Operating Cash Flow	($1,152)	($10,841)
5	PV of Capital	($125,755)	($24,540)
6	PV of CCA Tax Shield	$17,896	$3,461
7	Total NPV	($109,011)	($31,919)

Key Assumptions:

- Discount rate of 5.60% [2025 after tax WACC].
- Replacement in-service date assumed to be December 2027.
- Replacement costs escalated in accordance with internal Enbridge Gas guidelines.
- Inspect & Repair option assumes the pipeline will be inspected on a 15-year cycle.
- Inspect & Repair costs escalated at 3% per annum, with original costs expressed in 2025 dollars.

Table 2.
NPV Results for NPS 12 Martin Grove Pipeline Long-term Mitigation Alternatives

NPS 12 Martin Grove: NPV Summary ($000's)

Line No.	Particulars	Replacement Option	Inspect & Repair Option
	Cost Elements (Escalated)	2026 to 2066	
1	Net Operating Cash Flow	($1,166)	($9,561)
2	Total Capital	($53,803)	($12,489)
3	CCA Tax Shield	$12,909	$2,459
	Net Present Value (NPV)		
4	PV of Operating Cash Flow	($197)	($3,886)
5	PV of Capital	($51,022)	($6,952)
6	PV of CCA Tax Shield	$6,986	$914
7	Total NPV	($44,233)	($9,924)

Key Assumptions:

- Discount rate of 5.60% [2025 after tax WACC].
- Replacement in-service date assumed to be December 2027.
- Replacement costs escalated in accordance with internal Enbridge Gas guidelines.
- Inspect & Repair option assumes the pipeline will be inspected on a 15-year cycle.
- Inspect & Repair costs escalated at 3% per annum, with original costs expressed in 2025 dollars.

As described in Exhibit G, Tab 4, Schedule 1, pages 17-18, the remaining three pipelines in-line inspected in 2024 did not have an NPV analysis completed.

The NPS 8 St. Thomas pipeline was determined to be fit-for-service and, therefore, no mitigation alternatives were required to be evaluated. Accordingly, an NPV analysis was not necessary.

The NPS 10 Sarnia South and NPS 8 Port Stanley pipelines did not have sufficient data available at the time of the original QRA to accurately assess the risk associated with compression couplings and aerial crossings. Updated QRAs for both pipelines were completed in September 2026 and are currently under review to determine appropriate long-term mitigation alternatives. An NPV analysis will be completed if multiple feasible alternatives are identified and require evaluation and comparison.

b) The original QRAs completed in 2025 for each of the five EDIMP pipelines selected for in-line inspection in 2024 are provided as attachments to this response.

c) Enbridge Gas has identified several opportunities for Asset Life Extensions through improved understanding of pipe condition from inline inspections. Pipelines are prioritized for inspection and assessment based on several key factors such as soil

type, age, coating type, failure history, and consequence of failure. The results, however, can be difficult to predict and therefore difficult to extrapolate between different pipelines that appear to have similar characteristics.

Within the same pipeline, inline inspection results for the sample portions of pipeline are extrapolated to uninspected portions with similar characteristics. This is used to assess overall pipeline risk from representative condition data.

Enbridge Gas will continue to look for opportunities to use the results from past inspections and assessments to improve the prioritization model used to select future pipelines.

NPS 12 Wilson Avenue Pipeline - Quantitative Risk Assessment (QRA)

June 4, 2025

ENBRIDGE

Integrity Assessments & Risk

Integrity Department

Document Governance

Revision History

Date	Version	Prepared By	Approved By
2025-06-04	1.0	Carly Li Engineer in Training II, Integrity Assessment & Risk, Pipelines & Storage	Kai Ji, P.Eng. Supervisor, Integrity Assessment & Risk, Pipelines & Storage

1. Introduction

The NPS 12 Wilson Avenue pipeline was identified as a 2024 EDIMP priority pipeline and in-line inspections (ILIs) were performed in 2024 to assess the condition of the line.

Subsequently, a Quantitative Risk Assessment (QRA) has been conducted to assess the risk of the NPS 12 Wilson Avenue pipeline. Methodologies used in the QRA are similar to those used in the St. Laurent Pipeline (SLP) Replacement Project [1]. This report summarizes the QRA performed, and the results will be utilized to develop long-term risk mitigation plans for the NPS 12 Wilson Avenue pipeline.

2. Background Information

2.1 Pipe Properties

The pipeline characteristics that comprise the majority of the NPS 12 Wilson Avenue pipeline are shown in Table 2.1. A detailed breakdown of the complete pipeline characteristics can be found in Appendix A: Pipeline Characteristics Maps.

Table 2.1: Primary Pipeline Specifications

Attribute	Specification	Assumptions
NPS	12	
Length	11.39 km	
Install Year	1962 (Majority - 69.5%), 1955 (Original - 3.0%)	
MOP	175 psi	Assumed based on pressure class (HP).
Wall Thickness	6.35 mm	Assumed based on NDE reports.
Grade	207 MPa	Assumed based on pipe vintage and the company's historical purchasing practices.
Coating	Coal Tar	Assumed based on 2024 integrity digs.
% SMYS	14.9%	Based on assumed values.

2.2 Inspection

2.2.1 Coverage

ILI runs across three launch sites were completed at various locations along the NPS 12 Wilson Avenue pipeline using the Intero Pipe Explorer 10/14 Axial MFL-LDS robotic crawler inspection tool between May 29th, 2024 and June 10th, 2024. The ILIs captured condition data on 2.93 km (26%) of the pipeline. The inspection extents and locations are shown in Figure 2.1.

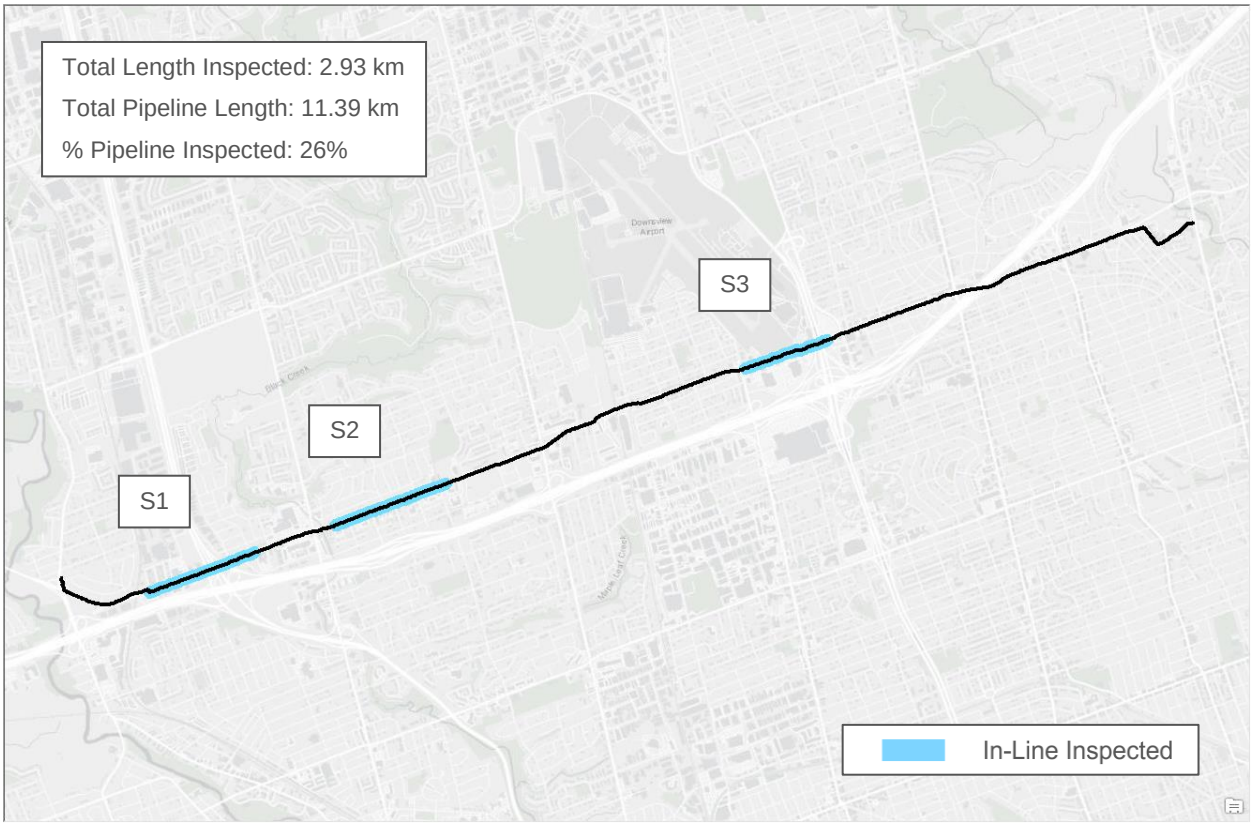


Figure 2.1: Crawler Inspection Extents and Locations

2.2.2 Metal Loss Results (MFL Technology)

A total of 939 metal loss features above the reporting threshold were reported along the inspected portions of the pipeline. 27 individual anomalies were identified with metal loss greater or equal to 70% wall loss (Phase 1) and the majority of these anomalies were located between Billy Bishop Way and Dufferin Street as part of inspection S3. The number of reported metal loss features by inspection and the resulting feature densities are shown in Table 2.2.

Table 2.2: Reported Metal Loss Features by Inspection

Inspection	Length Inspected (km)	Metal Loss Count	Features / km
S1	1.034	189	182.8
S2	1.087	281	258.5
S3	0.809	469	579.9
Total	**2.930**	**939**	**320.5**

As shown in Figure 2.2, metal loss counts were dominated by features found on S3 which exhibited higher corrosion density than the other inspections.

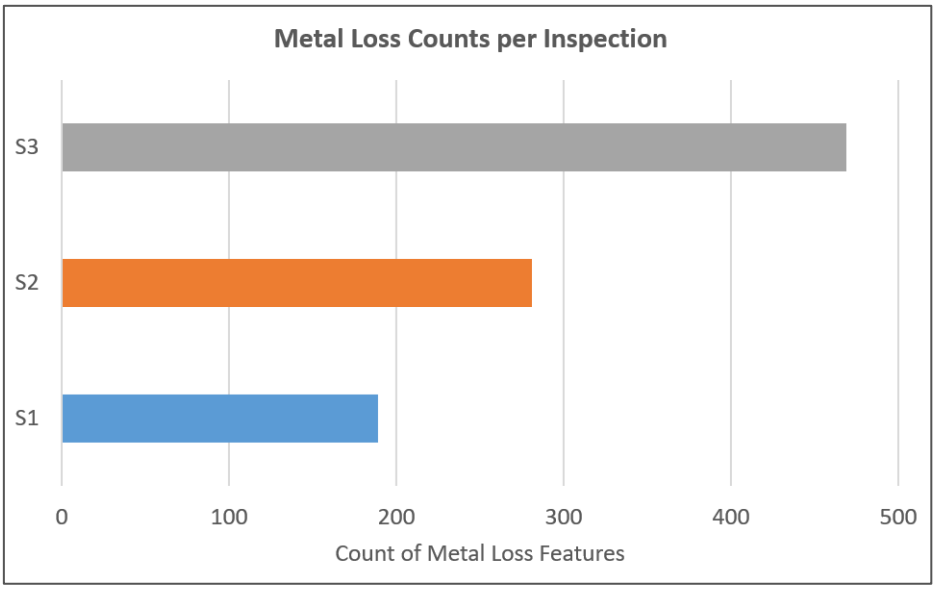


Figure 2.2: Metal Loss Counts per Inspection

A histogram showing the count of corrosion depths reported by inspection is shown in Figure 2.3 and the majority of the most severe features were found on S3.

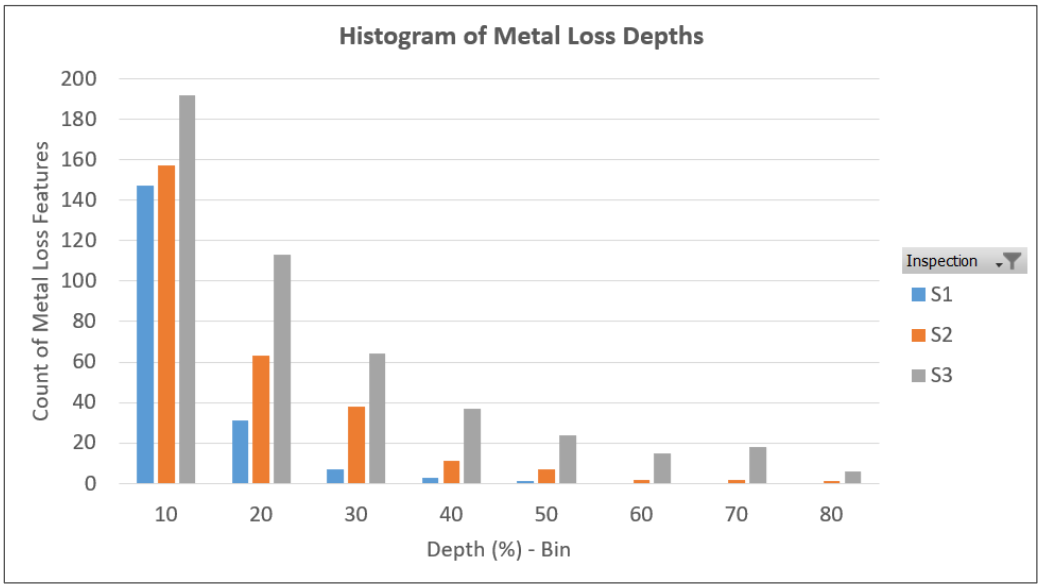


Figure 2.3: Histogram of Metal Loss Depths

2.2.3 Deformation Results (LDS Technology)

A total of 14 dent features above the reporting threshold were reported along the inspected portions of the pipeline as shown in Table 2.3.

Table 2.3: Reported Dents by Inspection

Inspection	Length Inspected (km)	Dent Count	Dents / km
S1	1.034	5	4.8
S2	1.087	3	2.8
S3	0.809	6	7.4
Total	**2.930**	**14**	**4.8**

Of the dents reported, 8 (57%) were reported as top-side (above the 4 and 8 o'clock positions). In addition, 2 dents had a depth greater than 2% of the pipeline outer diameter and 2 dents were identified as interacting with metal loss. The details of the more significant dents separated by inspection are shown in Table 2.4.

Table 2.4: Significant Dents by Inspection

Inspection	Top-side Dents	Dents > 2%	Dents with Metal Loss
S1	2	1	1
S2	3	0	1
S3	3	1	0
Total	**8**	**2**	**2**

3. Reliability

The reliability of the NPS 12 Wilson Avenue pipeline was quantitively assessed by evaluating the susceptibility of the pipeline to corrosion and third-party damage (TPD) threats with potential to cause a loss of containment (LoC) failure.

There are multiple modes which a LoC can occur and are categorized by three release sizes:

- Small Leak
- Large Leak
- Rupture

CSA Z662 Annex O further categorizes the modes into two distinct Limit State categories [2]:

- Leakage Limit State (LLS)
- Ultimate Limit State (ULS)

Definitions can be found in Section 3.1 in the SLP QRA [1].

3.1 Corrosion Threat

3.1.1 Reliability Based on Historical Leaks

A statistical reliability assessment approach was used by observing the pipeline's leak history and considering a plausible set of ranges for the historical leak rate as shown in Table 3.1. For the NPS 12 Wilson Avenue pipeline (11.39 km), an average historical leak rate is calculated to be 4.88E-03 per km.yr based on available leak record history. On the other hand, using tacit knowledge from Operations SMEs results in an average historical leak rate of 1.01E-02 per km.yr. Applying a Poisson distribution of incidence rates at 95% confidence results in extended confidence bounds, and failure rates above these bounds are plausible as the Poisson distribution assumes that events occur randomly whereas the corrosion threat is known to increase with time.

Table 3.1: Average Historical Leak Rate

Term	Leak Record History	Tacit Knowledge from Operations SMEs
Leaks	1. 2017 leak due to corrosion which was permanently repaired in 2018	1. 1999 leak due to suspected corrosion 2. 2018 leak due to corrosion and excavation damage 3. 2020 leak due to corrosion
Time Period	18 years (2007 - 2024)	26 years (1999 - 2024)
Average Historical Leak Rate	4.88E-03 per km.yr	1.01E-02 per km.yr
Average Historical Leak Rate with 95% Confidence Interval	1.24E-04 per km.yr to 2.72E-02 per km.yr	2.09E-03 per km.yr to 2.96E-02 per km.yr

3.1.2 Reliability Based on Inspection Data

3.1.2.1 Reliability for Inspected Portions

After the inspections, Enbridge Gas completed multiple repairs to mitigate Phase 1 anomalies shown in Table 3.2.

Table 3.2: Completed Repairs

Inspection	Repair	Location
S2	Pressure containment sleeve	Wilson Avenue and Springview Avenue
	Pressure containment sleeve	Wilson Avenue and Montana Avenue
S3	Piping cut-out and replacement of ~463m	Wilson Avenue and Billy Bishop Way
	Piping cut-out and replacement of ~2m	Wilson Avenue and William R. Allen Road
	~2m of piping was coated and wrapped	Wilson Avenue and Dufferin Street

A structural reliability model was used to calculate the reliability of the pipeline's inspected portions based on the reported ILI corrosion features by applying the ASME Modified B31G failure criterion and a Probability of Exceedance (POE) approach. As such, the small leak average failure rates along the inspected portions are calculated to be 8.33E-02 per km.yr before the repairs and 2.93E-04 per km.yr after the repairs as shown in Table 3.3.

Table 3.3: Average Failure Rates for Inspected Portions Before and After Repairs

Inspection	Length Inspected (km)	Average Failure Rate per km.yr (Before Repairs)	Average Failure Rate per km.yr (After Repairs)
S1	1.034	3.13E-05	3.13E-05
S2	1.087	2.70E-02	4.14E-04
S3	0.809	2.66E-01	4.66E-04
Average	**2.930**	**8.33E-02**	**2.93E-04**

3.1.2.2 Reliability for Uninspected Portions

To estimate the condition for the rest of the pipeline, ILI results before repairs from the 2.93 km of inspections were extrapolated to uninspected segments using a like-in-kind approach. The like-in-kind approach involves defining “like” segments of pipeline which are considered to have similar key characteristics that are known to influence corrosion.

Factors such as the pipe body coating and corrosion area (i.e., areas defining continuous cathodic protection) were considered for defining the appropriate like-in-kind segments. However, the majority of the pipeline was assumed to be coated with coal tar, so the like segments were defined based on the corrosion area. This resulted in groups 1 to 6 shown in Table 3.4 where each group represents a different corrosion area. Groups 1 to 3 have been partially inspected and piping within each group share the same key characteristics (e.g., wall thickness and vintage) and therefore, condition information from inspected segments was extrapolated to uninspected like segments on the assumption that they exhibit similar corrosion conditions within each group. Groups 4 to 6 have not been inspected and were assigned the average failure rate of all ILIs.

Since inspection data was only collected for pipe installed between 1957 and 1962, the conditions of these segments were only considered representative for older pipe vintages. The like-in-kind approach was therefore only applied to pipe installed from 1955 to 1967. More modern pipes were considered to be in better condition and therefore more reliable; in order to capture this assumed increased reliability, pipes installed between 1970 and 1990 were assigned a failure rate of 1.00E-05 per km.yr and pipes installed after 1990 were assigned a failure rate of 1.00E-06 per km.yr based on SME judgement that the time-dependent corrosion threat is low for these vintages. This resulted in groups 7 and 8 as shown in Table 3.4.

Table 3.4: Pipeline Grouping Based on Like-In-Kind

Type	Group	Corrosion Area	Length (km)	% of Total Pipeline Length	% Inspected	Average Failure Rate per km.yr for Uninspected
Older pipe - Portions of CA have been inspected	1	E4030	2.22	19.5%	47%	3.13E-05 (S1)
	2	F4047	2.20	19.4%	49%	2.70E-02 (S2)
	3	H4029	3.23	28.4%	25%	2.66E-01 (S3)
Older pipe - No portions of CA have been inspected	4	F4033	0.05	0.5%	0%	8.33E-02 (All ILIs)
	5	G4025	1.17	10.3%	0%	
	6	I4013	2.09	18.3%	0%	
Modern pipe - Uninspected (1970 - 1990)	7	-	0.32	2.8%	0%	1.00E-05 (SME)
Modern pipe - Uninspected (1991 - Present)	8	-	0.10	0.9%	0%	1.00E-06 (SME)

Figure 3.1 shows the geospatial locations of the like-in-kind groupings in relation to the inspected portions of the pipeline.

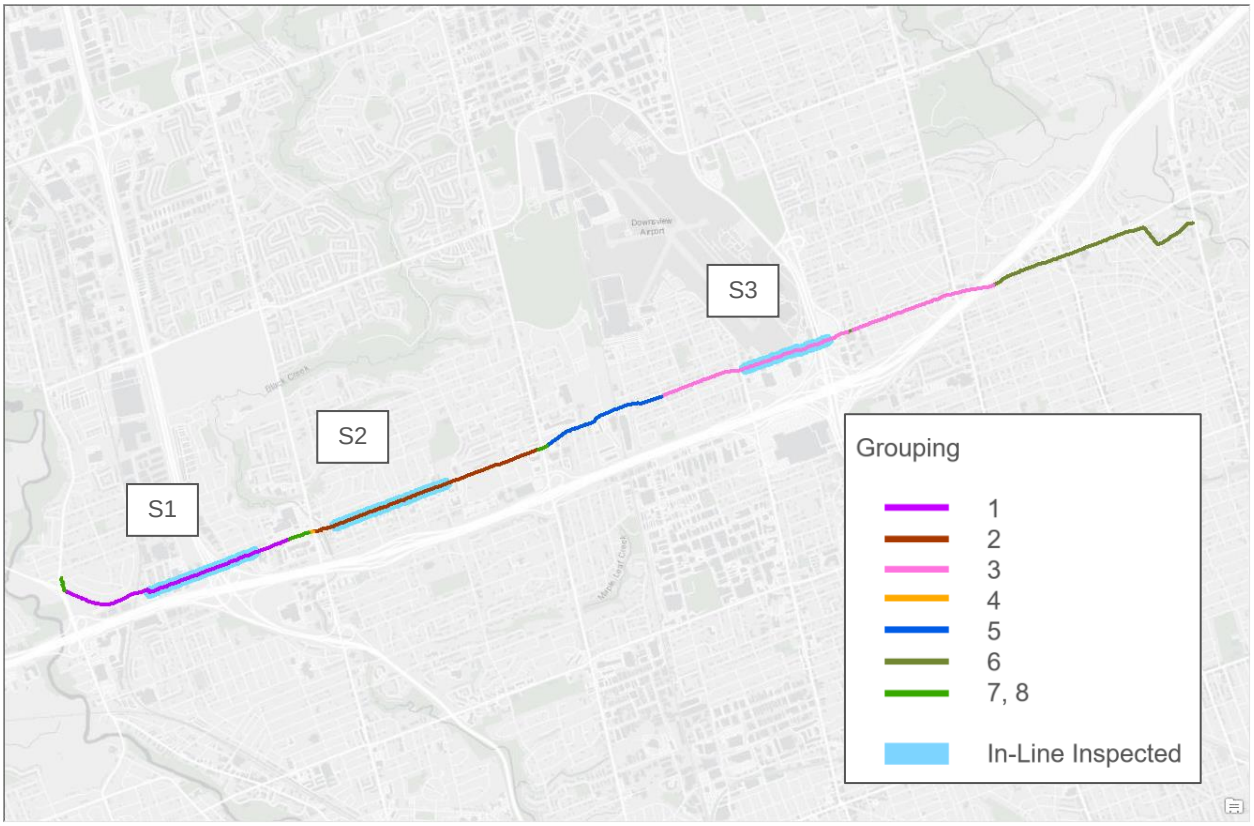


Figure 3.1: Pipeline Groupings with ILI Locations Overlaid

3.1.2.3 Reliability for Full Pipeline

The total pipeline is estimated to have a small leak average failure rate of 8.34E-02 per km.yr based on the inspection data extrapolated to the uninspected portions. The calculated average failure rates from the inspected and uninspected portions are summarized in Table 3.5.

Table 3.5: Summarized Corrosion Reliability Results

Pipeline	Length (km)	Average Failure Rate per km.yr (Before Repairs)	Average Failure Rate per km.yr (After Repairs)
Inspected Portions	2.93	8.33E-02	2.93E-04
Uninspected Portions	8.46	1.12E-01	1.12E-01
Total	**11.39**	**1.05E-01**	**8.34E-02**

3.2 Third-Party Damage Threat

The failure rate due to TPD was calculated following an industry accepted framework and is expressed as the product of the expected hit rate from third-party equipment, a depth of cover (DOC) adjustment factor, and the probability that a hit results in a LoC.

3.2.1 Pipeline Hit Rate Based on Inspection and Depth of Cover

3.2.1.1 Observed Hit Rate on Inspected Portions

To distinguish likely TPD from non-TPD related dents, a filtering criterion was applied to the 14 dents reported by the ILI tool to estimate the number of dents that were likely due to mechanical excavator damage. The filtering criterion applied was:

- Subset of top-side dents which are specifically occurring on the top half of the pipeline (between 8:00 and 4:00 o'clock) where mechanical damage is most likely, AND either one of the following criteria:
    - Dents interacting with Metal Loss, OR
    - Dents > 2% of the pipeline outer diameter

This resulted in a final count of 2 significant dents that were considered to be caused by historical mechanical excavator damage. The results of the filtering criterion applied to the inspections and the resulting hit rates are shown in Table 3.6.

Table 3.6: Significant Dents Suspected to be TPD Hits by Inspection

Inspection	Length Inspected (km)	Dents Meeting TPD Filtering Criterion	Hits / km
S1	1.034	1	1.0
S2	1.087	1	0.9
S3	0.809	0	0.0
Total	**2.930**	**2**	**0.7**

3.2.1.2 Estimated Hit Rate on Uninspected Portions

The TPD hit rate for the uninspected portions of the pipeline was estimated using the TPD hit rate for the inspected portions as it was assumed that the third-party excavation activity rate was constant at all locations along the pipeline.

DOC has been shown to be a predominant factor that influences the hit rate from TPD. As such, a DOC adjustment factor is used as a multiplicative term that is applied on an estimate of hit frequency at a system mean depth of 1.5 m.

To calculate the average hit rate per km.yr, the count of dents suspected to be caused by TPD were first normalized based on the DOC at which they were found by applying the inverse of the DOC adjustment factor as shown in Table 3.7. This has the effect of normalizing the number of dents (and by extension, the resulting hit rate) to a system mean depth of 1.5 m, which allows for the average hit rate calculated from these counts to take into account the DOC for the remainder of the pipeline using the DOC adjustment factor.

Table 3.7: Normalized Dents by Inspection

Inspection	Length Inspected (km)	Dents	Normalized Dent Count
S1	1.034	1	0.63
S2	1.087	1	0.62
S3	0.809	0	0
Total	**2.930**	**2**	**1.25**

3.2.1.3 Estimated Hit Rate for Full Pipeline

To estimate the hit rate for the NPS 12 Wilson Avenue pipeline, the normalized dent count was divided by the number of km-years of pipeline service (i.e., pipeline exposure) of the inspected portions. The average hit rate for the full pipeline without considering DOC data along the pipeline is calculated as 6.91E-03 per km.yr. When considering the DOC, the average hit rate is 9.13E-03 per km.yr. Details are shown in Table 3.8.

Table 3.8: Average Hit Rates for Full Pipeline

Total Normalized Dent Count of Inspected Portions	Exposure of Inspected Portions (km.yrs)	Average Hit Rate per km.yr (Non-Adjusted for DOC)	Average Hit Rate per km.yr (Adjusted for DOC)
1.25	181.29	6.91E-03	9.13E-03

3.2.2 Probability of Damage, Given a Hit

The probability of damage given an excavator strike was estimated using a structural reliability model that estimates the impact force of the strike and the pipeline's structural resistance to damage. Impact force and pipe resistance were modelled as random variables that account for the uncertainty in pipeline characteristics (e.g., wall thickness, ultimate tensile strength (UTS), Charpy toughness, etc.), as well as the uncertainty in load from the excavator.

Puncture and gouged dent modes of failure were considered in the probability of damage assessment, and a simplifying (but not necessarily conservative) assumption was made that both failure modes are predicted to result in large leak failure, corresponding to the Annex O ULS category. More details on the assessment can be found in Section 4.1.2 in the DIMP Risk Algorithm Document (RAD) [3]. The calculated probability of damage based on the unique combination of pipe properties for the majority of the line is 6.21E-02 as shown in Table 3.9.

Table 3.9: Probability of Damage Based on Pipeline Properties

Grade (MPa)	NPS	WT (mm)	2/3 CVN (J)	UTS (MPa)	MOP (psi)	Class Location	Probability of Damage
207	12	6.4	10	427	175	3	6.21E-02

3.2.3 Third-Party Damage Failure Rate

The TPD large leak failure rate for the full pipeline was calculated by multiplying the average hit rate after adjusting for the DOC and the probability of damage, given a hit. The large leak rate was also converted into an equivalent rupture rate using Equation O.4 in CSA Z662-23 Annex O [2]. As a result, the estimated large leak rate is 5.67E-04 per km.yr and the corresponding equivalent rupture failure rate is 1.25E-05 per km.yr as shown in Table 3.10.

Table 3.10: TPD Large Leak and Equivalent Rupture Failure Rates

Length (km)	Average Hit Rate per km.yr (Adjusted for DOC)	Probability of Damage	Large Leak Failure Rate per km.yr	Equivalent Rupture Failure Rate per km.yr
11.39	9.13E-03	6.21E-02	5.67E-04	1.25E-05

4. Tolerable Reliability Levels

4.1 Reliability Thresholds

The CSA Z662 Annex O standard provides guidance for operators to apply reliability-based thresholds to their pipeline systems for the LLS and ULS categories.

The LLS reliability threshold for natural gas pipelines is recommended to be 1.0E-03 per km.yr based on a combination of leak impact analysis, historical leak rates, and calibration to ASME B31.8 and CSA Z662 [2].

The ULS reliability threshold for natural gas pipelines is developed by considering the risk of natural gas ignited releases on human safety. The consequences of natural gas pipeline failure are proportional to the population density ρ, probability of ignition, and the hazard area; since the probability of ignition is approximately proportional to the diameter D, and hazard area is proportional to PD^2 where P is the pipeline pressure, the reliability thresholds are defined as an increasing function of ρPD^3. For an NPS 12 pipeline at 175 psi MOP in a Class 3 (urban) location, the ULS threshold is recommended to be 9.1E-05 per km.yr [2].

4.2 Segment Reliability

Failure rates for each individual 100 m segment are shown in Figures 4.1 and 4.2 for the LLS and ULS categories, respectively, along with their respective limits and targets. The LLS limit and target have been set by adopting the Annex O LLS threshold as the limit (i.e., red line) and one order of magnitude lower than the limit as the target (i.e., green line). For ULS, the Annex O ULS threshold has been adopted as the limit and the Enbridge ULS threshold (1.0E-05 per km.yr) has been adopted as the target.

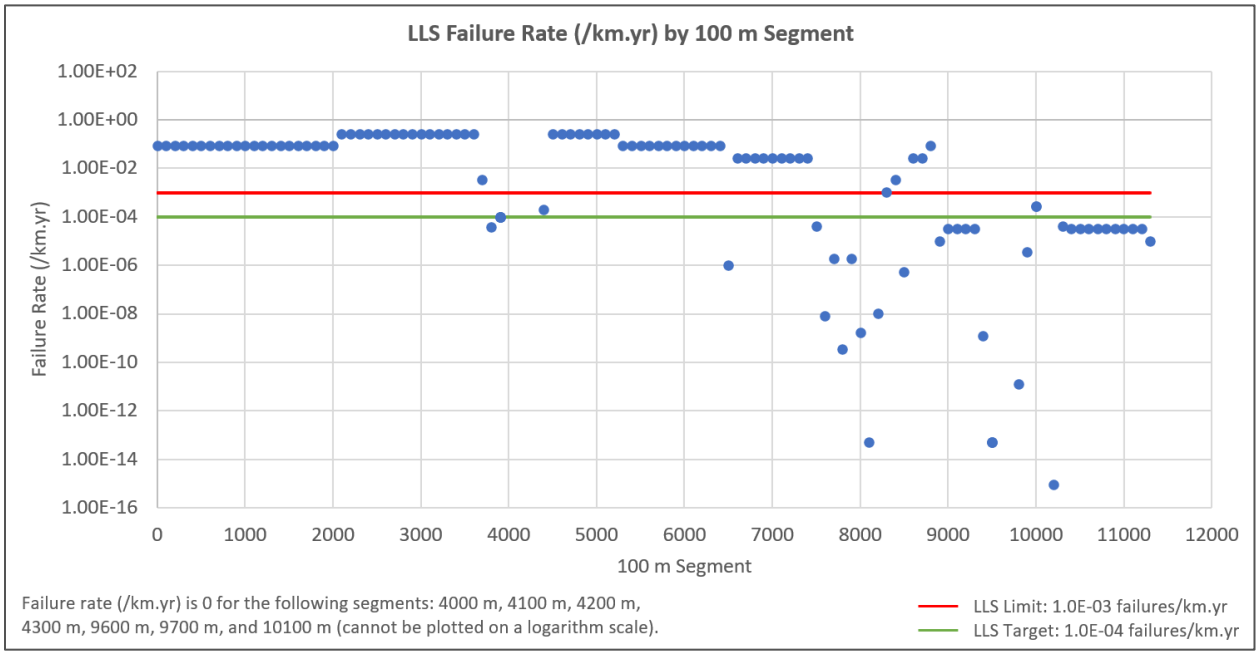


Figure 4.1: NPS 12 Wilson Avenue Pipeline - Annex O LLS Assessment

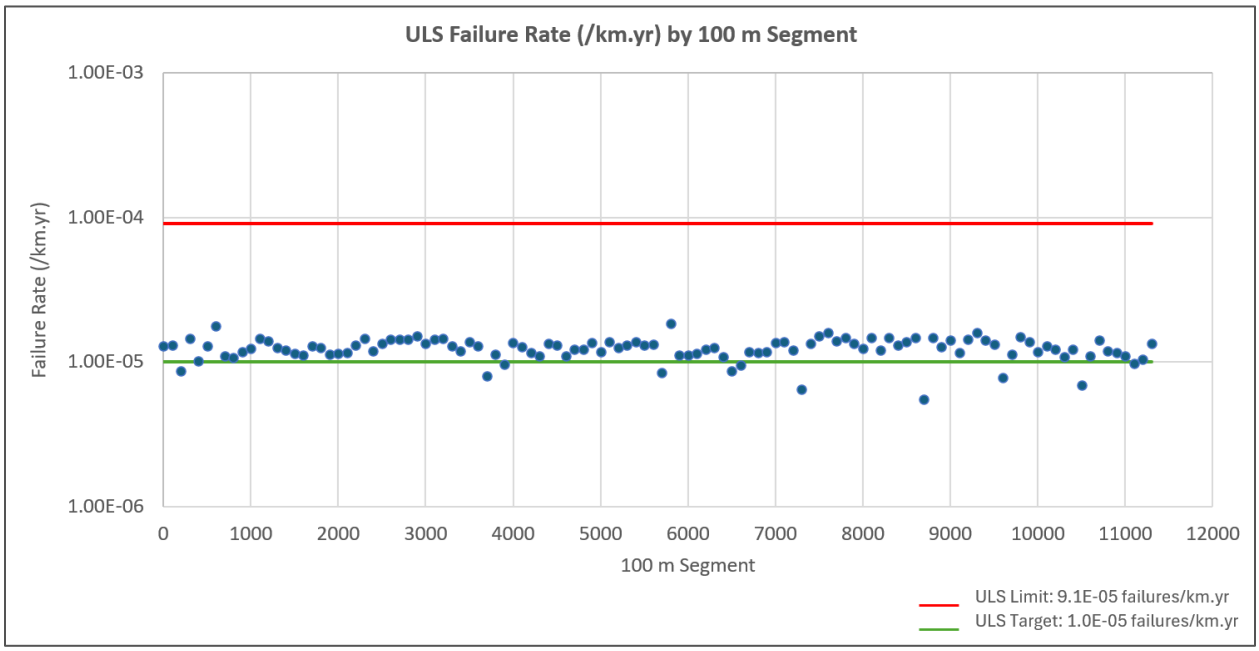


Figure 4.2: NPS 12 Wilson Avenue Pipeline - Annex O ULS Assessment

4.3 Reliability Maps

Figures 4.3 and 4.4 show the reliability of the pipeline based on the LLS and the ULS, respectively, with 100 m segmentation granularity where the east end is considered as the pipeline start (i.e., 0 m). Colouring has been applied based on each limit state's respective limit and target.

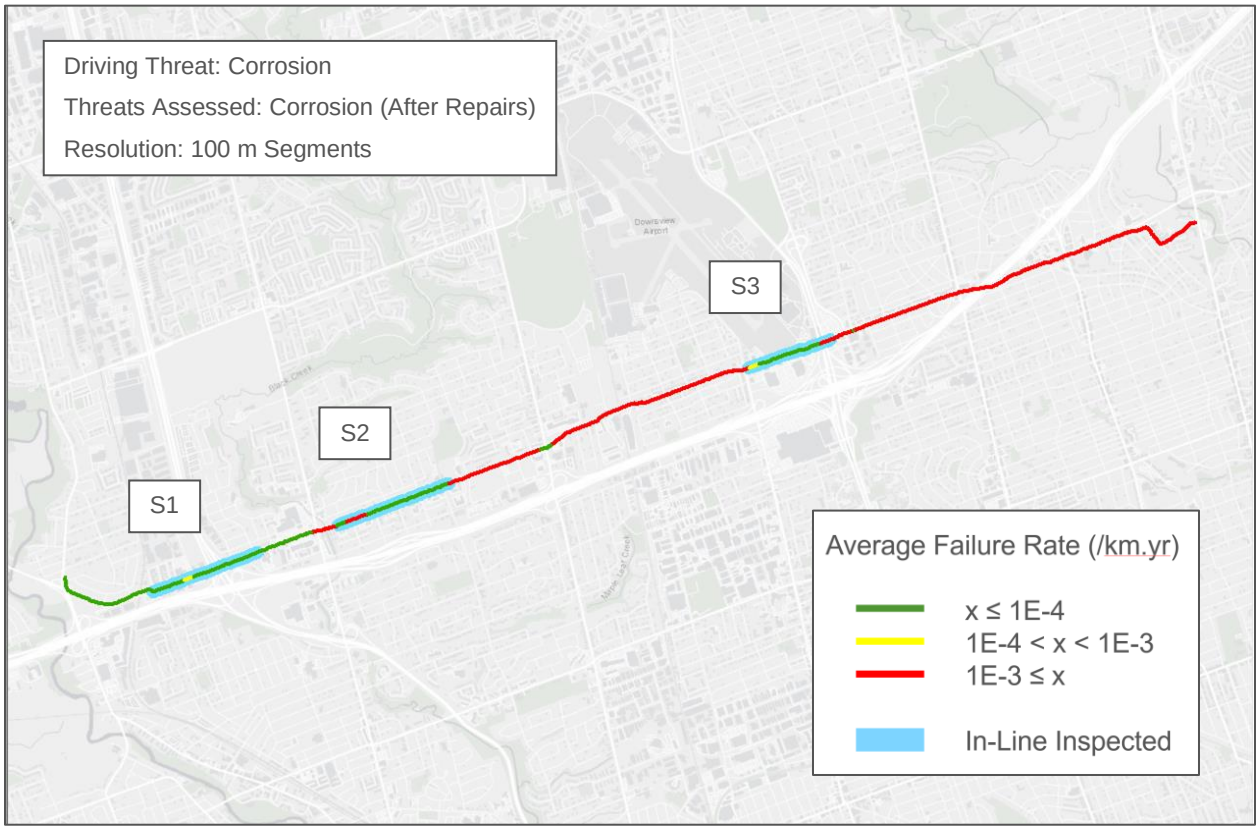


Figure 4.3: NPS 12 Wilson Avenue Pipeline - LLS Map (100 m Segments)

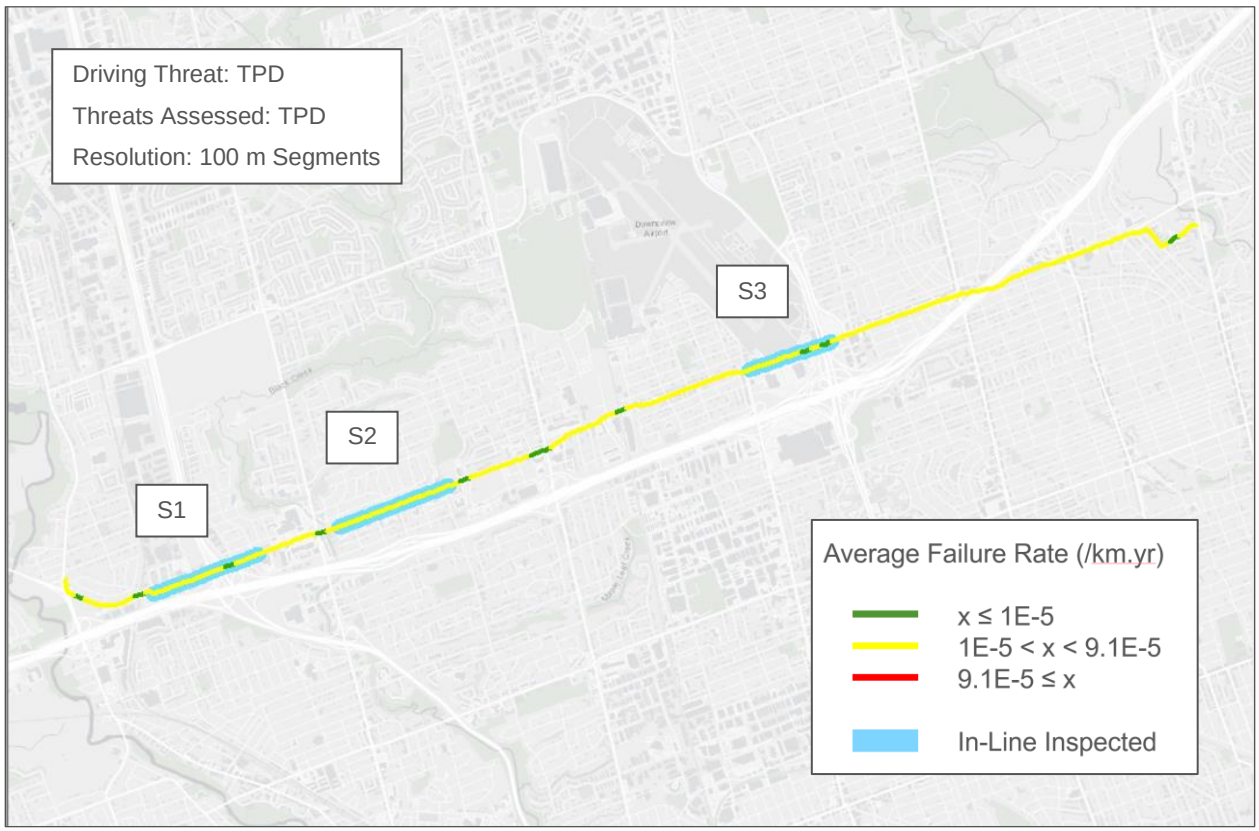


Figure 4.4: NPS 12 Wilson Avenue Pipeline - ULS Map (100 m Segments)

Figure 4.5 shows the overall reliability of the pipeline by combining the LLS and ULS categories as assessed against their respective limits and targets. The combined reliability map is coloured based on the worst-case reliability level from either the LLS or ULS map (i.e., “Above Limit” means that either the LLS or ULS limit was exceeded).

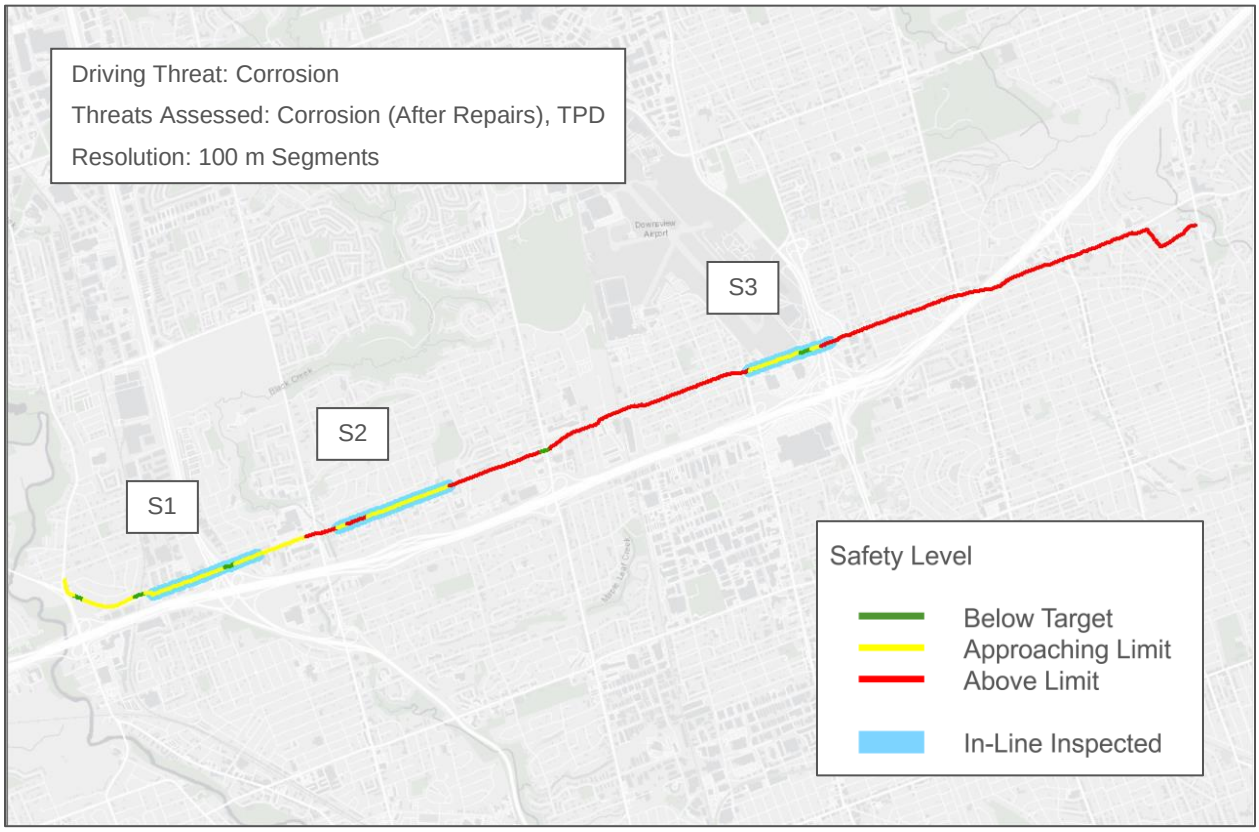


Figure 4.5: NPS 12 Wilson Avenue Pipeline - Combined Map (100 m Segments)

Based on Figure 4.5, the safety level of three 100 m segments within the inspected portions is above the LLS or ULS limit as shown in Table 4.1. All three segments are driven by Phase 2 metal loss anomalies and the required repairs are pending.

Table 4.1: Inspected Segments with Safety Level Above Limit

100 m Segment	Inspection	Safety Level	Driving Threat	Driving Anomaly FID
3700 - 3800 m	S3	Above Limit	Corrosion	59 (Metal Loss)
8300 - 8400 m	S2	Above Limit	Corrosion	547 (Metal Loss)
8400 - 8500 m	S2	Above Limit	Corrosion	564 (Metal Loss)

5. Significant Incidents on Distribution Assets

Based on PHMSA incident data on distribution pipelines, a hazard rate of approximately 5.89E-06 per km.yr of significant incidents (meeting PHMSA's reporting thresholds) was observed for corrosion and excavation damage only [4]. This rate can act as a benchmark for operators of distribution networks with an objective to perform better than the historical average of significant incidents in distribution pipelines across the industry.

Table 5.1 summarizes the reliability of the NPS 12 Wilson Avenue pipeline according to the CSA Z662 Annex O LLS and ULS categories along with their equivalent significant incident rate which is aligned with the PHSMA significant incident definition. Significant incident rates were calculated based on PHMSA distribution annual report data between 2010-2024 that shows approximately 18% of corrosion leaks and 89% of excavation damage failures resulted in a "hazardous leak". Given the urban environment that the NPS 12 Wilson Avenue pipeline traverses, it is expected that all leaks meeting the definition of "hazardous" would also meet PHMSA "significant" incident criteria.

The significant incident rate estimated for the NPS 12 Wilson Avenue pipeline is orders of magnitude higher than the historical per km average of significant incidents across the industry (only corrosion and TPD threats considered).

Table 5.1: Failure Rates Converted to Equivalent Significant Incident Rates

Threat	Small Leak (/km.yr)	Large Leak (/km.yr)	Significant Incident Rate (/km.yr)
Corrosion	8.34E-02	0	1.50E-02
TPD	0	5.67E-04	5.04E-04
Total			**1.55E-02**

6. Enbridge Operational Risk Assessment Matrix Mapping

The Enbridge Operational Risk Assessment Matrix was applied to the assessment of scenarios that could result in health and safety impacts to the public, customer disruption, or financial losses. The risk matrix was performed by leveraging the assessed reliability in Section 3 with additional conditional probabilities that a given outcome will occur and potential consequences resulting from the scenario. The consequences were determined by consulting with SMEs and incorporating data-driven models, where available. The full scope of the NPS 12 Wilson Avenue pipeline (11.39 km) was applied in mapping the scenarios to the risk matrix.

6.1 Health & Safety Risk

6.1.1 Health & Safety Outcome 1 (HS1) - Migration and Explosion of Nearby Structure

Pipeline leaks may pose a significant health and safety risk if gas migrates into a nearby building and causes an explosion. In this scenario, an underground leak migrates through the soil or via below-ground infrastructure, reaches an enclosed area or structure, accumulates to ignitable gas concentrations, and encounters an ignition source.

Due to its proximity to multiple nearby buildings, in the event of a small or large leak, the NPS 12 Wilson Avenue pipeline is considered susceptible to gas migration and explosion.

6.1.1.1 HS1 Probability

The probability of a migration and explosion event was determined by multiplying the probability of a failure by the conditional probability that the leak may migrate into a nearby building and cause an explosion as shown in Table 6.1. The conditional probabilities of migration-explosion have been determined though a review of migration-related ignitions in the PHMSA incident repository and represent system-wide averages. Using system-wide averages resulted in unconservative estimates of migration-explosion probabilities as the NPS 12 Wilson Avenue pipeline is assessed to have a higher-than-average susceptibility based on the environment in which it operates (e.g., higher number of roadways and hard surfaces and longer periods of frozen soil in the regional climate, which prevent gas from being able to permeate to the surface). The full details of the approach to determine condition probabilities of migration-explosion are outlined in Section 5.1.1 in the DIMP RAD [3]. The probability of a migration and explosion event on the NPS 12 Wilson Avenue pipeline is 1.73E-04 events/yr.

Table 6.1: Probability of Migration and Explosion

Threat	Probability of Migration and Explosion Given a Failure (Industry Average for Steel Mains)	Probability of a Failure (/yr)	Probability of Migration and Explosion (/yr)
Corrosion (Small Leak)	1.79E-04	9.50E-01	1.70E-04
TPD (Large Leak)	4.09E-04	6.45E-03	2.64E-06
Total			**1.73E-04**

6.1.1.2 HS1 Consequence

The NPS 12 Wilson Avenue pipeline is considered to have high possible health and safety consequences as the pipeline traverses a highly urban location and is in close proximity to many residential, commercial, and office buildings. Based on a satellite imagery survey commissioned by Enbridge Gas [5], there are 498 buildings within 50 m of the pipeline in which a migration-explosion event is possible. The consequences due to health and safety are qualitatively estimated based on its location and Section 5.3.1 in the DIMP RAD [3] and are shown in Table 6.2.

Table 6.2: Fatality Risks of a Migration and Explosion Event

Estimate	Fatality	Justification
Minimum	0.5	The minimum fatality consequence assumes an explosion in an unoccupied structure, likely only resulting in possible injuries.
Most Likely	1	The best estimate for fatality consequence for a mix of residential, multi-residential, and commercial structures.
Maximum	20	The maximum fatality consequence assumes a failure near a larger office, commercial buildings, or religious facilities. It also includes failures in buildings which may take longer to evacuate such as schools or health care settings.

6.1.2 Health & Safety Outcome 2 (HS2) - Local Ignition at Failure Site

Large leaks may also pose a significant health and safety risk through immediate or delayed ignition near the source of the failure. In this scenario, ignition may occur immediately if sufficient kinetic energy is present in the initial moment of burst, or after a slight delay until the gas encounters a nearby ignition source (e.g., excavation equipment). Both jet fires and flash fires have been observed in industry on distribution pipelines.

6.1.2.1 HS2 Probability

The probability of a local ignition event was determined by multiplying the probability of a failure by the conditional probability that the large leak ignites as shown in Table 6.3. The probability of local ignition at the failure site can be estimated by calculating the expected mass flowrate of gas following failure described in Section 5.2 in the DIMP RAD [3] and using the ignition probabilities for an urban release listed in the OGP Report 434-6.1 [6]. The probability of a local ignition event on the NPS 12 Wilson Avenue pipeline is 7.68E-05 events/yr.

Table 6.3: Probability of Local Ignition

Threat	Release Rate (kg/s)	Probability of Local Ignition Given a Failure	Probability of Failure (/yr)	Probability of Local Ignition (/yr)
Large Leak	2.71	0.01	6.45E-03	7.68E-05
Total				**7.68E-05**

6.1.2.2 HS2 Consequence

The health and safety consequences of a local ignition event can vary from injuries to fatalities depending on the magnitude of the fire and the number and vulnerability of people present. Due to the highly urban location that the NPS 12 Wilson Avenue pipeline traverses through and Wilson Avenue being a key route for different modes of transportation (e.g., walking, bicycling, and driving), it is expected that a local jet fire event would pose a high health and safety risk to the public. These consequences are qualitatively estimated as shown in Table 6.4. On the other hand, Wilson Avenue is underneath highly travelled motorways such as Highway 400, Allen Road, and Highway 401, but it is assumed that the motorways' concrete shields vehicles from potential jet fires.

Table 6.4: Fatality Risks of a Local Ignition Event

Estimate	Fatality	Justification
Minimum	0.5	No fatalities and possible injuries.
Most Likely	1	The best estimate for fatality consequence assumes a failure with an exposed individual present (likely during excavation activities).
Maximum	10	The maximum fatality consequence assumes a failure affecting a highly populated area along the NPS 12 Wilson Avenue pipeline.

6.1.3 Health & Safety Risk - Operational Risk Assessment Matrix Mapping

The results of the assessed health and safety risk outcomes for the full scope of the NPS 12 Wilson Avenue pipeline are shown in Figure 6.1.

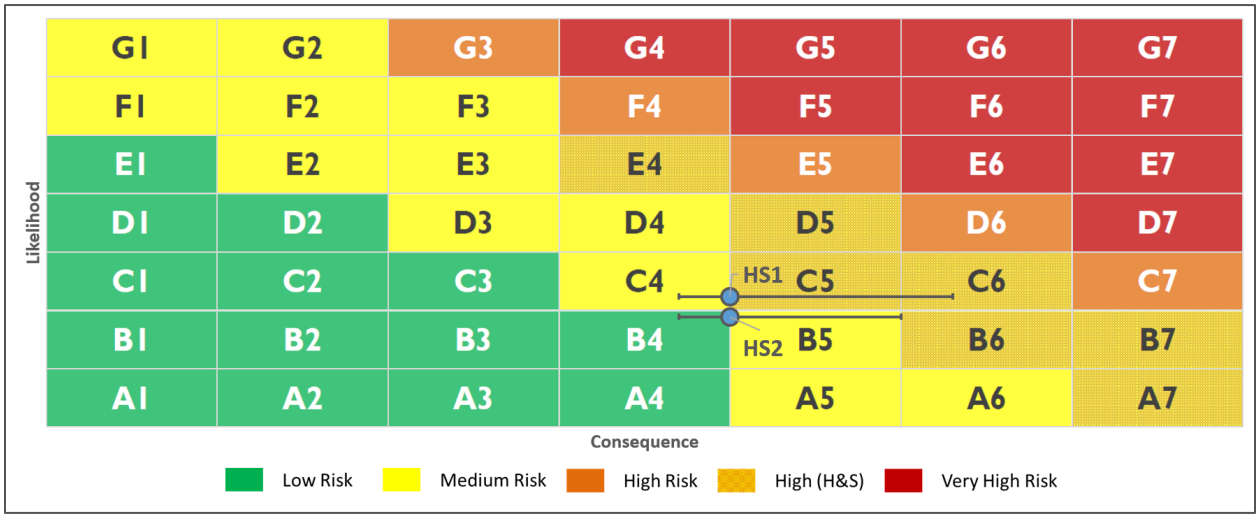


Figure 6.1: Enbridge Operational Risk Assessment Matrix - Health & Safety Risk

6.2 Operational Disruption Risk

6.2.1 Operational Disruption Outcome 1 (OD1) - Customer Losses Due to Operational Disruptions

In an emergency where a leak on a pipeline is confirmed, Enbridge's top priority is to perform "Make Safe" actions to protect its workers and the public from harm. Enbridge will also consider any possible environmental impacts of a large leak on the pipeline to ensure it meets its Environmental, Social, and Governance (ESG) commitments. Based on a case-by-case assessment, it may be required to perform an immediate isolation of the hazardous pipe segment by closing nearby valves or restricting the gas flow using a "squeeze-off" technique, resulting in potential customer loss.

6.2.1.1 OD1 Probability

The probability of an operational disruption event was determined by multiplying the probability of a failure by the conditional probability that the failure would lead to an operational disruption as shown in Table 6.5. Conditional probabilities were based on SME judgement and industry data. The probability of an operational disruption event on the NPS 12 Wilson Avenue pipeline is 1.47E-02 events/yr.

Table 6.5: Probability of Operational Disruption

Threat	Probability of Operational Disruption Given Failure	Probability of Failure (/yr)	Probability of Operational Disruption (/yr)
Small Leak	0.01	9.50E-01	9.50E-03
Large Leak	0.80	6.45E-03	5.16E-03
Total			**1.47E-02**

6.2.1.2 OD1 Consequence

Customers that are reliant on this pipeline system include those in residential and commercial buildings, who count on a reliable, dependable energy source for their daily operations. A review of gas demand has been completed to assess the customer impact of a service shutdown (i.e., isolation using mainline valves) on the NPS 12 Wilson Avenue pipeline for a range of scenarios including 0 degree day (summer), fall peak, and design day. In addition to the outside temperature, the location at which the failure occurs along the pipeline can impact the number of customer losses, resulting in a large range of possible outcomes. A qualitative assessment of the operational disruption consequences was completed by comparing the simulated customer loss scenarios with the business-unit specific operational disruption consequence criteria as shown in Table 6.6.

Table 6.6 Operational Disruption Customer Loss

Estimate	Customer Loss Consequence Category	Justification
Minimum	2	Isolation in the event of an emergency for a 0 degree day (summer) scenario.
Most Likely	5	Isolation in the event of an emergency for a fall peak scenario.
Maximum	6	Isolation in the event of an emergency for a design day scenario.

6.2.2 Operational Disruption Risk - Operational Risk Assessment Matrix Mapping

The result of the assessed operational disruption risk outcome for the full scope of the NPS 12 Wilson Avenue pipeline is shown in Figure 6.2.

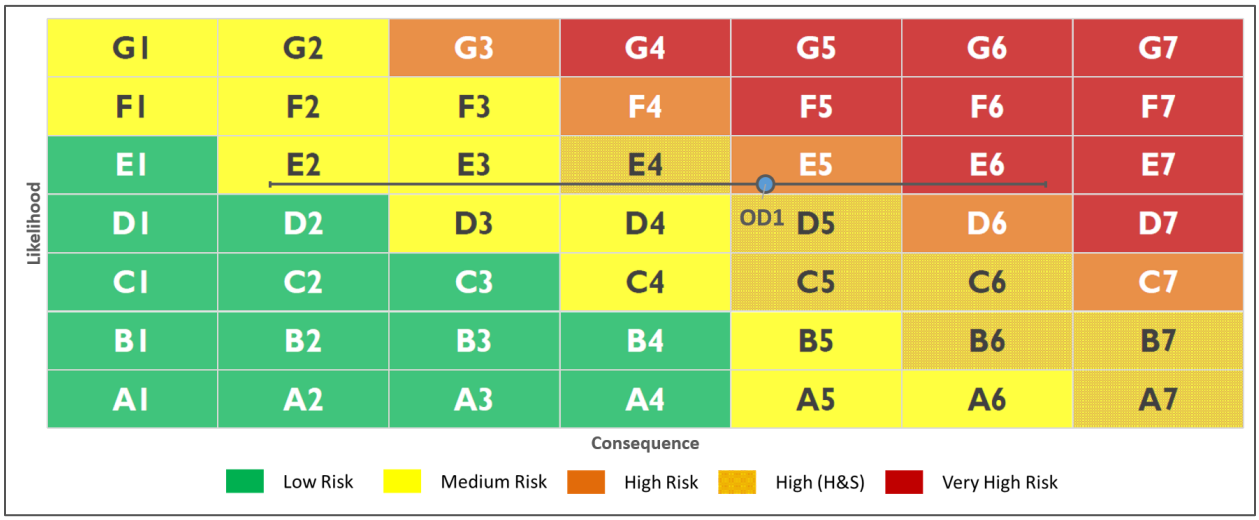


Figure 6.2: Enbridge Operational Risk Assessment Matrix - Operational Disruption Risk

6.3 Financial Risk

6.3.1 Financial Outcome 1 (F1) - Small Leak Resulting in Pipeline Repair or Replacement

The highest financial risk is associated with the scenario of a small leak on the NPS 12 Wilson Avenue pipeline where an immediate repair of the pipeline is necessary and will result in repair costs including planning, permitting, excavation, and materials. Given the immediate need for the repair, the emergency nature of the work will increase the costs in comparison to the same work completed on a planned basis due to expedited planning and permitting requirements and overtime work. In addition, timing of the repair cannot be planned to minimize gas demands resulting in the possibility of performing a repair at a time of the year with high gas demands, requiring installation of larger bypass piping (if bypass is possible) to mitigate any customer impacts.

6.3.1.1 F1 Probability

The probability of a pipeline repair is the product of the small leak failure rate and the total length of the pipeline, which is calculated to be 0.95 events/yr on the NPS 12 Wilson Avenue pipeline.

6.3.1.2 F1 Consequence

The costs associated with a repair of a small leak on the NPS 12 Wilson Avenue pipeline were determined through consultation with Engineering Construction SMEs. The cost estimates were based on recent excavation, repair, and replacement projects on the NPS 12 Wilson Avenue pipeline as described in Section 3.1.2.1. However, using the costs of digs and repairs on a planned basis results in unconservative cost estimates as opposed to an emergency repair scenario.

Given that the costs of a leak can vary based on the repair type and if third-party contractors are involved, the consequences are presented as a range of values as shown in Table 6.7.

Table 6.7 Pipeline Repair Costs of Corrosion Leak

Estimate	Value ($)	Justification
Minimum	$95,000	Assumes the repair type is a recoat where the repair execution is completed internally and an internal gas pipeline inspector is used.
Most Likely	$155,000	Assumes the repair type is a pressure containment sleeve where the repair execution is completed by a third-party contractor and an internal gas pipeline inspector is used.
Maximum	$210,000	Assumes the repair type is a cut-out where the repair execution is completed by a third-party contractor and an external gas pipeline inspector is used.

6.3.2 Financial Risk - Operational Risk Assessment Matrix Mapping

The result of the assessed financial risk outcome for the full scope of the NPS 12 Wilson Avenue pipeline is shown in Figure 6.3.

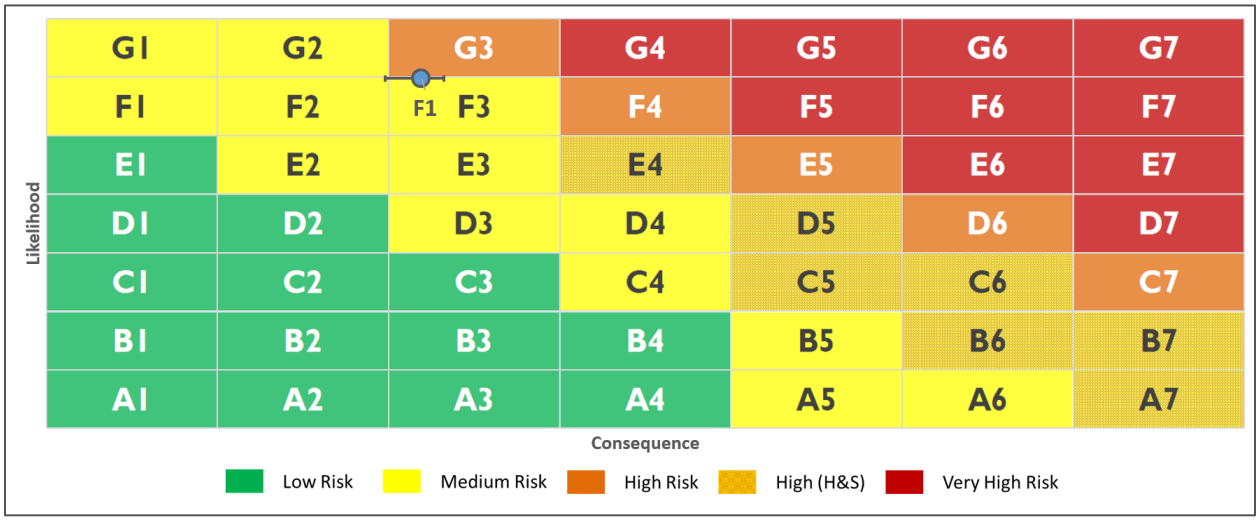


Figure 6.3: Enbridge Operational Risk Assessment Matrix - Financial Risk

6.4 Combined Operational Risk Assessment Matrix Plot

The most significant risks associated with a failure of the NPS 12 Wilson Avenue pipeline are overlayed in Figure 6.4. This mapping uses a combination of quantitative inputs and qualitative assessments to assess the risk based on the Enbridge Operational Risk Assessment Matrix. As such, various possible outcomes on the NPS 12 Wilson Avenue pipeline meet the enterprise Safety & Reliability Framework definition of “Medium Risk” or “High Risk”.

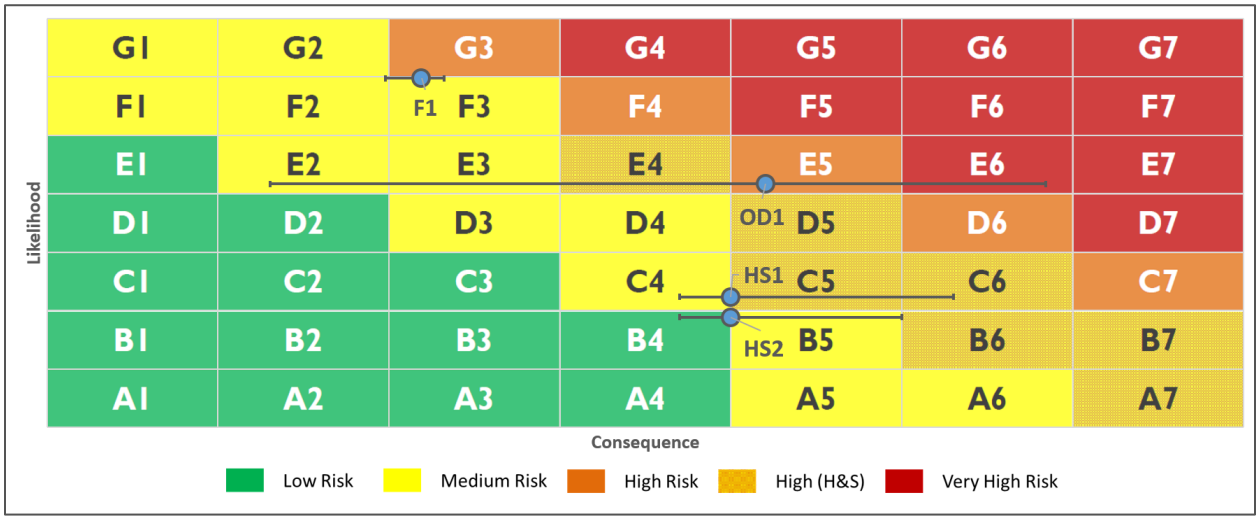


Figure 6.4: Enbridge Operational Risk Assessment Matrix - All Significant Outcomes

7. Recommendations

A risk assessment utilizing a defense-in-depth approach was conducted to evaluate the reliability and risk of the NPS 12 Wilson Avenue pipeline considering corrosion and TPD threats to its pipeline integrity.

Failure rates were calculated based on historical information and best practice reliability models and then compared to industry benchmarks. The assessment supports the following conclusions:

- 7.2 km of the 11.39 km pipeline (63%) is assessed to have a small leak failure rate above the 1.0E-03 per km.yr LLS limit described by CSA Z662 Annex O.
- 0 km of the 11.39 km pipeline (0%) is assessed to have a large leak (or equivalent rupture) failure rate above the 9.1E-05 per km.yr ULS limit described by CSA Z662 Annex O for an NPS 12 pipeline at 175 psi MOP in a Class 3 (urban) location.
- Integrating the LLS and ULS approaches, 7.2 km of the 11.39 km pipeline (63%) fails one or both reliability limits.

In addition to benchmarking with industry standard CSA Z662 thresholds, an assessment was performed to compare the estimated significant incident rates on the NPS 12 Wilson Avenue pipeline to significant incident rates observed on typical distribution pipelines. This assessment concluded that the pipeline-specific significant incident rates for the NPS 12 Wilson Avenue pipeline are orders of magnitude higher than the historical per km average observed in the industry.

To take into account the overall risks of a failure on the pipeline system, the quantitative reliability assessment was supplemented with consequences of various outcomes and mapped to the Enbridge Operational Risk Assessment Matrix. This exercise concluded that various risk scenarios meet the Enbridge Operational Risk Assessment Matrix definition of “Medium Risk” or “High Risk”.

Based on the combination of the three evaluation methods described, it is determined that remedial action is required to improve the reliability of 7.2 km of the NPS 12 Wilson Avenue pipeline to meet industry benchmarks and the Enbridge enterprise acceptable risk levels. This length is non-continuous and does not consider practical considerations of any possible remedial actions.

References

[1] Enbridge Gas Inc. (2024). *Quantitative Risk Assessment (QRA) - St. Laurent North Pipeline* (EB-2024-0200, Exhibit B, Tab 1, Schedule 1, Attachment 2). Ontario Energy Board.

[2] Canadian Standard Association. (2023). *CSA Z662:23 Oil and Gas Pipeline Systems - Annex O Reliability-based design and assessment (RBDA) of onshore non-sour service natural gas transmission and LVP liquid hydrocarbon pipelines* (CSA Z662:23).

[3] Integrity Assessments - Enbridge Gas Inc. (2021). *PRIM Distribution Risk Model - Risk Algorithm Document*. Internal document: unpublished.

[4] Lyons, S. & Modarres, M. (2020). Understanding Risks: Natural Gas Distribution Piping in the United States. *Proceedings of the 2020 13th International Pipeline Conference*. IPC2020-9238.

[5] Integrity Assessments - Enbridge Gas Inc. (2023). Enertech Building Footprints and Human Occupancy Dataset [File Geodatabase].

[6] International Association of Oil & Gas Producers. (2010). *OGP Risk Assessment Data Directory - Ignition Probabilities* (Report No. 434 – 6.1).

Appendix A: Pipeline Characteristics Maps

Wall Thickness

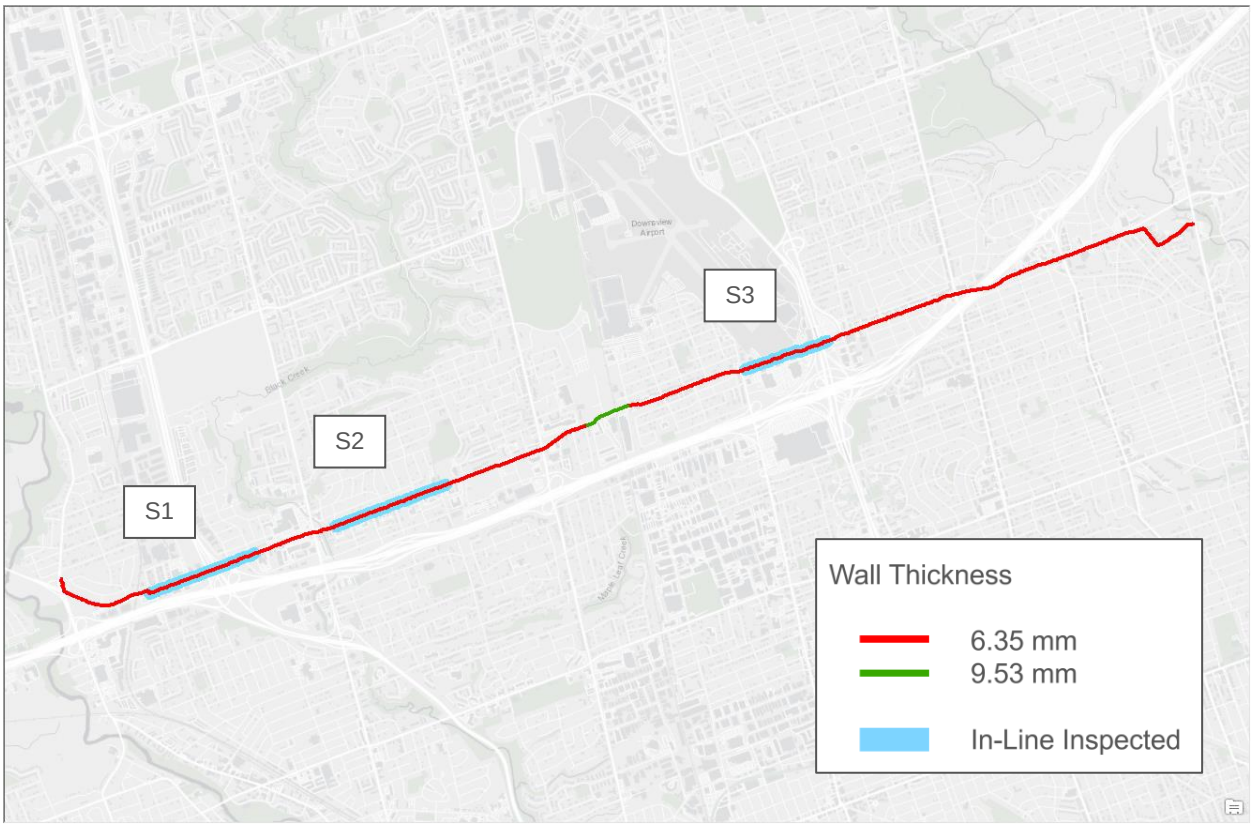


Figure A.1: NPS 12 Wilson Avenue Pipeline - Wall Thickness

Grade

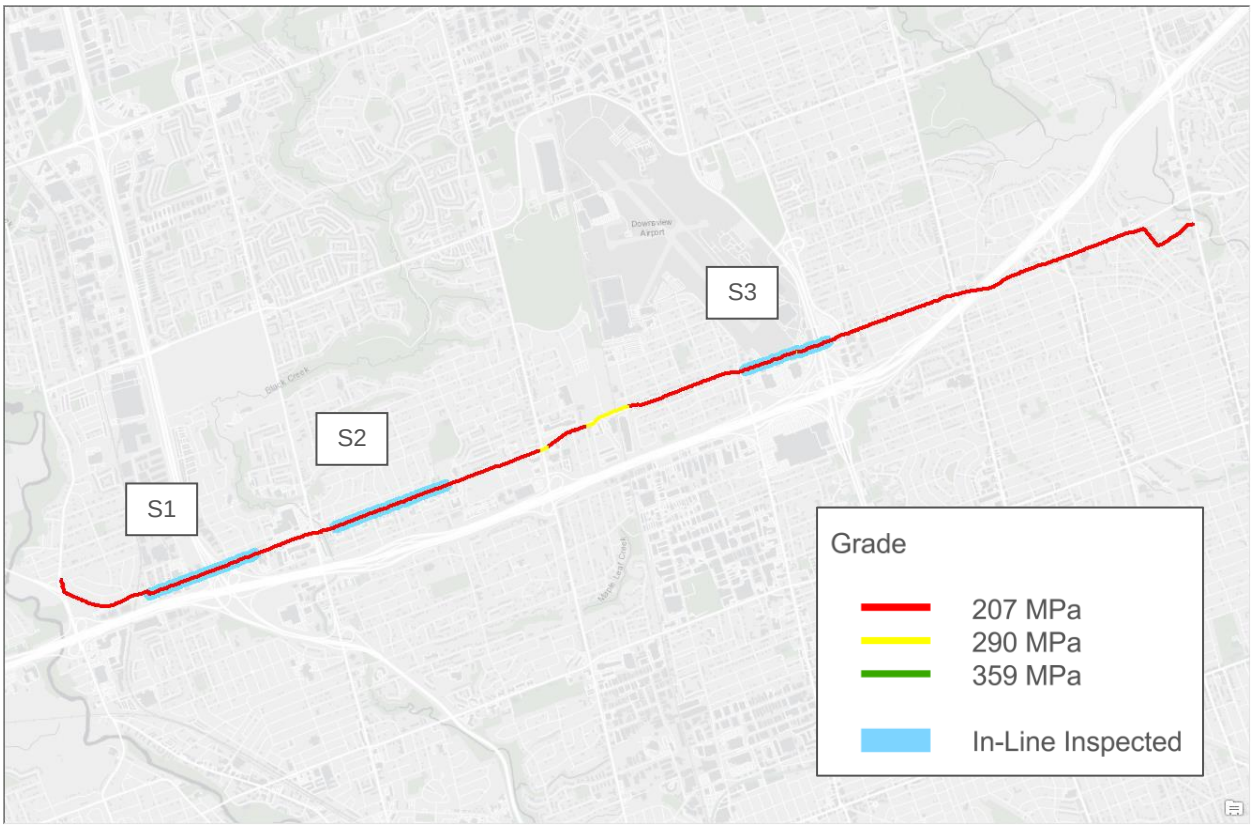


Figure A.2: NPS 12 Wilson Avenue Pipeline - Grade

Coating



Figure A.3: NPS 12 Wilson Avenue Pipeline - Coating

Install Year

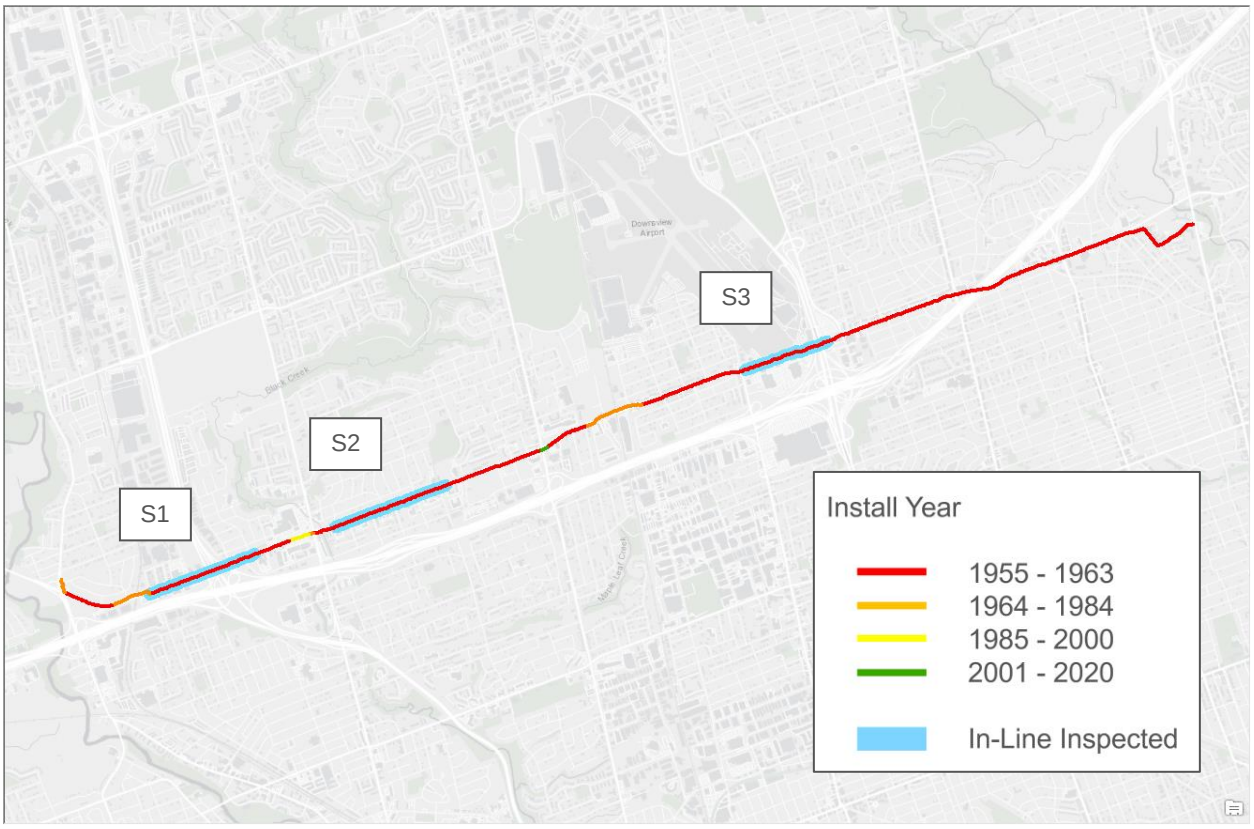


Figure A.4: NPS 12 Wilson Avenue Pipeline - Install Year

Corrosion Area



Figure A.5: NPS 12 Wilson Avenue Pipeline - Corrosion Area

NPS 12 Martin Grove Pipeline - Quantitative Risk Assessment (QRA)

October 1, 2025

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Integrity Department

Document Governance

Revision History

Date	Version	Prepared By	Approved By
2025-10-01	1.0	Carly Li Engineer in Training II, Integrity Assessment & Risk, Pipelines & Storage	Kai Ji, P.Eng. Supervisor, Integrity Assessment & Risk, Pipelines & Storage

1. Introduction

The NPS 12 Martin Grove pipeline was identified as a 2024 EDIMP priority pipeline and in-line inspections (ILIs) were performed in 2024 to assess the condition of the line.

Subsequently, a Quantitative Risk Assessment (QRA) has been conducted to assess the risk of the NPS 12 Martin Grove pipeline. Methodologies used in the QRA are similar to those used in the St. Laurent Pipeline (SLP) Replacement Project [1]. This report summarizes the QRA performed, and the results will be utilized to develop long-term risk mitigation plans for the NPS 12 Martin Grove pipeline.

2. Background Information

2.1 Pipe Properties

The pipeline characteristics that comprise the majority of the NPS 12 Martin Grove pipeline are shown in Table 2.1. A detailed breakdown of the complete pipeline characteristics can be found in Appendix A: Pipeline Characteristics Maps.

Table 2.1: Primary Pipeline Specifications

Attribute	Specification	Assumptions
NPS	12	
Length	7.77 km	
Install Year	1955 (Majority - 46.4%) 1954 (Original - 2.4%)	
MOP	175 psi	Assumed based on pressure class (HP).
Wall Thickness	6.35 mm	Assumed based on NDE reports.
Grade	207 MPa	Assumed based on pipe vintage and the company's historical purchasing practices.
Coating	Coal Tar	Assumed based on NDE reports.
% SMYS	14.9%	Based on assumed values.

2.2 Inspection

2.2.1 Coverage

ILI runs across three launch sites were completed at various locations along the NPS 12 Martin Grove pipeline using the Intero Pipe Explorer 10/14 Axial MFL-LDS robotic crawler inspection tool between June 17th, 2024 and June 28th, 2024. The ILIs captured condition data on 2.45 km (32%) of the pipeline. The inspection extents and locations are shown in Figure 2.1.



Figure 2.1: Crawler Inspection Extents and Locations

2.2.2 Metal Loss Results (MFL Technology)

A total of 716 metal loss features above the reporting threshold were reported along the inspected portions of the pipeline. 3 individual anomalies were identified with metal loss greater or equal to 70% wall loss (Phase 1). The number of reported metal loss features by inspection and the resulting feature densities are shown in Table 2.2.

Table 2.2: Reported Metal Loss Features by Inspection

Inspection	Length Inspected (km)	Metal Loss Count	Features / km
S1	0.337	230	682.2
S2	1.154	351	304.3
S3	0.960	135	140.6
Total	**2.451**	**716**	**292.2**

As shown in Figure 2.2, metal loss counts were dominated by features found on S2. However, S1 exhibited higher corrosion density than the other inspections.

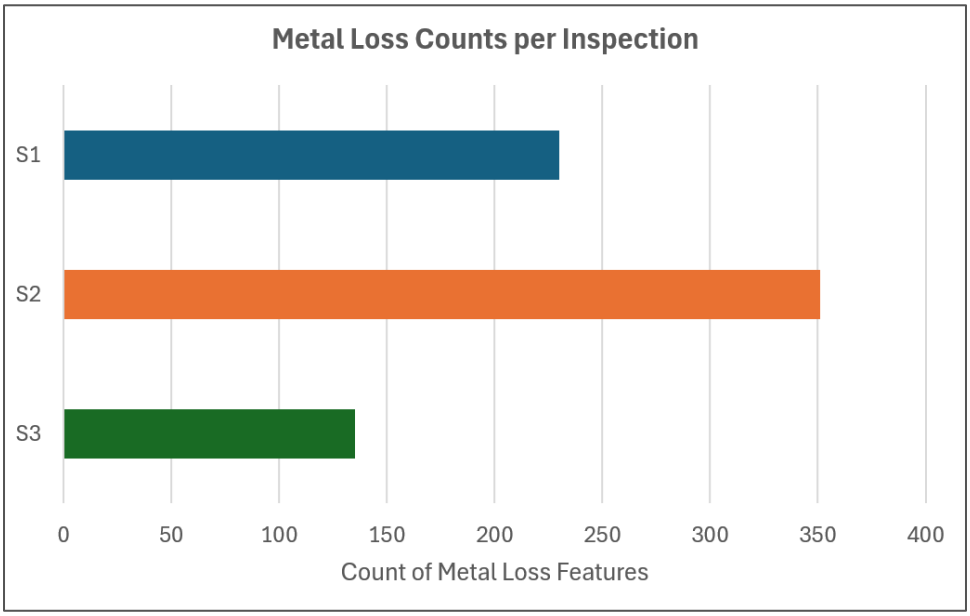


Figure 2.2: Metal Loss Counts per Inspection

The counts of corrosion depths reported by inspection are shown in Table 2.3 and Figure 2.3.

Table 2.3: Metal Loss Depths per Inspection

Depth (%) - Bin	S1	S2	S3
10	145	328	127
20	51	17	5
30	18	2	3
40	8	2	0
50	4	1	0
60	1	1	0
70	3	0	0

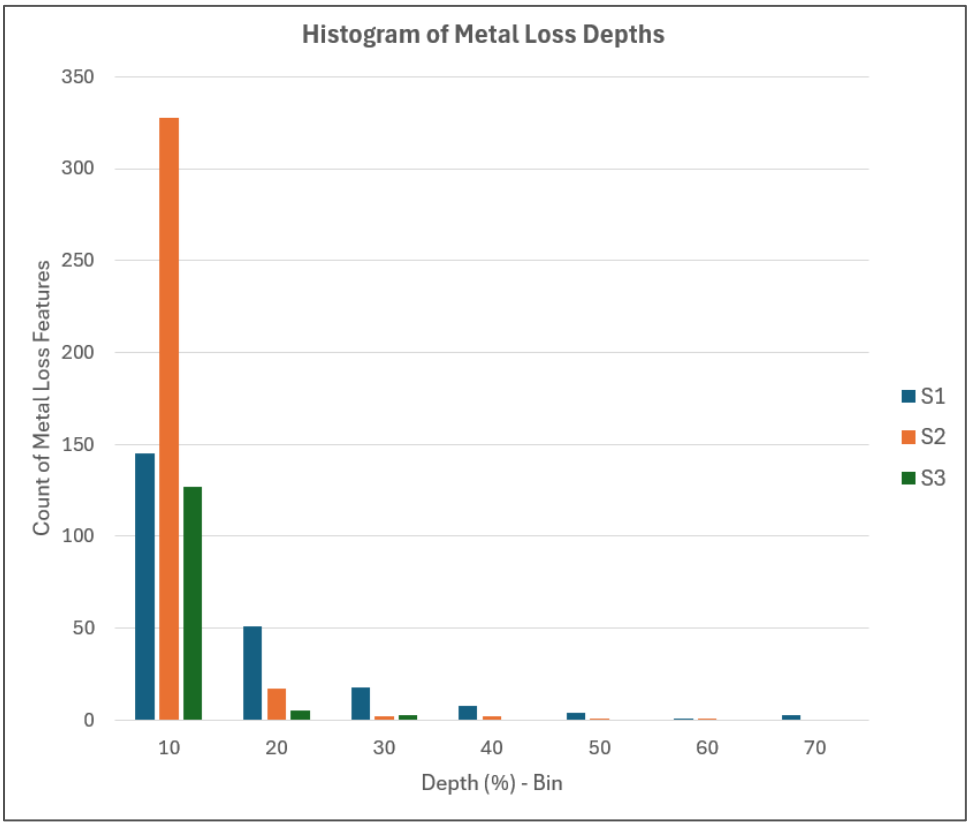


Figure 2.3: Histogram of Metal Loss Depths

2.2.3 Deformation Results (LDS Technology)

A total of 20 dent features above the reporting threshold were reported along the inspected portions of the pipeline as shown in Table 2.4.

Table 2.4: Reported Dents by Inspection

Inspection	Length Inspected (km)	Dent Count	Dents / km
S1	0.337	2	5.9
S2	1.154	6	5.2
S3	0.960	12	12.5
Total	**2.451**	**20**	**8.2**

Of the dents reported, 16 (80%) were reported as top-side (above the 4 and 8 o'clock positions). In addition, 2 dents had a depth greater than 2% of the pipeline outer diameter and 2 dents were identified as interacting with metal loss. The details of the more significant dents separated by inspection are shown in Table 2.5.

Table 2.5: Significant Dents by Inspection

Inspection	Top-side Dents	Dents > 2%	Dents with Metal Loss
S1	1	1	0
S2	6	0	1
S3	9	1	1
Total	**16**	**2**	**2**

3. Reliability

The reliability of the NPS 12 Martin Grove pipeline was quantitively assessed by evaluating the susceptibility of the pipeline to corrosion and third-party damage (TPD) threats with potential to cause a loss of containment (LoC) failure.

There are multiple modes which a LoC can occur and are categorized by three release sizes:

- Small Leak
- Large Leak
- Rupture

CSA Z662 Annex O further categorizes the modes into two distinct Limit State categories [2]:

- Leakage Limit State (LLS)
- Ultimate Limit State (ULS)

Definitions can be found in Section 3.1 in the SLP QRA [1].

3.1 Corrosion Threat

3.1.1 Reliability Based on Historical Leaks

A statistical reliability assessment approach was used by observing the pipeline's leak history and considering a plausible set of ranges for the historical leak rate as shown in Table 3.1. For the NPS 12 Martin Grove pipeline, both leak record history (18 years of data from 2007 to 2024) and tacit knowledge from an Operations SME (30 years of experience with the line) indicate that there have been no corrosion leaks on the pipeline body during its time. As such, the failure rate was estimated assuming one incident occurs in the near future which resulted in a failure rate of 6.77E-03 per km.yr or 4.29E-03 per km.yr, depending on whether the time period of leak record history or tacit knowledge from an Operation SME was used, respectively. Applying a Poisson distribution of incidence rates at 95% confidence results in extended confidence bounds, and failure rates above these bounds are plausible as the Poisson distribution assumes that events occur randomly whereas the corrosion threat is known to increase with time.

Table 3.1: Average Historical Corrosion Leak Rate

Term	Leak Record History	Operations SME
Leaks	0	0
Time Period	19 years (2007 - 2025)	30 years (1996 - 2025)
Average Historical Leak Rate (Assuming one leak in near future)[1]	6.77E-03 per km.yr	4.29E-03 per km.yr
Average Historical Leak Rate with 95% Confidence Interval	1.72E-04 per km.yr to 3.77E-02 per km.yr	1.09E-04 per km.yr to 2.39E-02 per km.yr

[1] The failure rate falls within the 95% confidence interval for an event with 0 recorded incidents using the statistical "rule of three".

3.1.2 Reliability Based on Inspection Data

3.1.2.1 Reliability for Inspected Portions

After the inspections, Enbridge Gas Ontario completed multiple repairs to mitigate Phase 1 anomalies as shown in Table 3.2.

Table 3.2: Completed Repairs

Inspection	Repair	Location
S1	Pressure containment sleeve, and coated and wrapped (~5 m)	Jopling Ave Street and Bloor Street West
	Pressure containment sleeve, and coated and wrapped (~5 m)	Jopling Ave Street and Bloor Street West
	Coated and wrapped (~8 m)	Aukland Road and Bloor Street West

A structural reliability model was used to calculate the reliability of the pipeline's inspected portions based on the reported ILI corrosion features by applying the ASME Modified B31G failure criterion and a Probability of Exceedance (POE) approach. As such, the average corrosion (small leak) failure rates along the inspected portions are calculated to be 1.42E-02 per km.yr before the repairs and 8.54E-04 per km.yr after the repairs as shown in Table 3.3.

Table 3.3: Average Corrosion Failure Rates for Inspected Portions Before and After Repairs

Inspection	Length Inspected (km)	Average Failure Rate per km.yr (Before Repairs)	Average Failure Rate per km.yr (After Repairs)
S1	0.337	9.80E-02	1.14E-03
S2	1.154	1.48E-03	1.48E-03
S3	0.960	1.72E-06	1.72E-06
Average	**2.451**	**1.42E-02**	**8.54E-04**

3.1.2.2 Reliability for Uninspected Portions

3.1.2.2.1 Older Pipe Vintages

To estimate the corrosion condition for the rest of the pipeline, ILI results before repairs from the 2.45 km of inspections were extrapolated to uninspected segments using a like-in-kind approach. The like-in-kind approach involves defining “like” segments of the pipeline which are considered to have similar key characteristics that are known to influence corrosion. Factors such as the pipe body coating and corrosion area (i.e., areas defining continuous cathodic protection) were considered for defining the appropriate like-in-kind segments.

Since inspection data was primarily collected for pipe installed in 1955 (over 97%), the conditions of the corresponding segments were only considered representative for older pipe vintages. The like-in-kind approach was therefore only applied to pipe installed before 1970, which is also primarily coated with coal tar. This resulted in groups 1 to 6 shown in Table 3.4 where each group represents a different corrosion area. Groups 1 to 4 have been fully or partially inspected, and condition information from each group’s inspected segments were extrapolated to uninspected like segments on the condition that piping shared the same key characteristics (e.g., wall thickness and vintage). Groups 5 and 6 have not been inspected and were assigned the average failure rate of all ILIs.

3.1.2.2.2 Modern Pipe Vintages

As inspection data for more modern pipe was limited, for pipe installed in 1970 and after, the corrosion failure rate was estimated using PIRAMID™ developed by C-FER Technologies, a historical-based reliability analysis method that utilizes threat-specific calibrated factors to update a baseline failure rate to account for pipeline-specific properties [3]. In this case, the baseline corrosion failure rate was determined using Enbridge Gas Ontario failure data for distribution steel mains. Modification factors included wall thickness, coating type, vintage, and soil corrosivity, as they influence the development, growth, and severity of corrosion on a pipeline.

3.1.2.2.3 Pipeline Groupings

Table 3.4 and Figure 3.1 depict the groupings for estimating corrosion reliability of the NPS 12 Martin Grove pipeline.

Table 3.4: Pipeline Groupings Based on Like-In-Kind

Type	Group	Corrosion Area	Length (km)	% of Pipeline
Uninspected: Older pipe - Portions of CA have been inspected	1	C9009	0.69	9%
	2	C8133	0.06	1%
	3	C7121	0.00	0%
	4	C7132	0.19	2%
Uninspected: Older pipe - No portions of CA have been inspected	5	C6101	1.01	13%
	6	C5087	0.56	7%
Uninspected: Modern pipe (1970 - present)	7	-	2.81	36%
Inspected	8	C9009, C8133, C7121, C7132	2.45	32%



Figure 3.1: Pipeline Groupings with ILI Locations Overlaid

3.1.2.3 Reliability for Full Pipeline

The total pipeline is estimated to have an average corrosion (small leak) failure rate of 1.12E-02 per km.yr based on the inspection data extrapolated to the uninspected portions. The calculated average failure rates from the inspected and uninspected portions are summarized in Table 3.5.

Table 3.5: Summarized Corrosion Reliability Results

Pipeline	Length (km)	Average Failure Rate per km.yr (Before Repairs)	Average Failure Rate per km.yr (After Repairs)
Inspected Portions	2.45	1.42E-02	8.54E-04
Uninspected Portions	5.32	1.60E-02	1.60E-02
Total	**7.77**	**1.54E-02**	**1.12E-02**

3.2 Third-Party Damage Threat

The failure rate due to TPD was calculated following an industry accepted framework and is expressed as the product of the expected hit rate from third-party equipment, a depth of cover (DOC) adjustment factor, and the probability that a hit results in a LoC.

3.2.1 Pipeline Hit Rate Based on Inspection and Depth of Cover

3.2.1.1 Observed Hit Rate on Inspected Portions

To distinguish likely TPD from non-TPD related dents, a filtering criterion was applied to the 20 dents reported by the ILI tool to estimate the number of dents that were likely due to mechanical excavator damage. The filtering criterion applied is:

- Subset of top-side dents which are specifically occurring on the top half of the pipeline (between 8:00 and 4:00 o'clock) where mechanical damage is most likely, AND either one of the following criteria:
    - Dents interacting with Metal Loss, OR
    - Dents > 2% of the pipeline outer diameter

This resulted in a final count of 3 significant dents that were considered to be caused by historical mechanical excavator damage. The results of the filtering criterion applied to the inspections and the resulting hit rates are shown in Table 3.6.

Table 3.6: Significant Dents Suspected to be TPD Hits by Inspection

Inspection	Length Inspected (km)	Dents Meeting TPD Filtering Criterion	Hits / km
S1	0.337	1	3.0
S2	1.154	1	0.9
S3	0.960	1	1.0
Total	**2.451**	**3**	**1.2**

3.2.1.2 Estimated Hit Rate on Uninspected Portions

The TPD hit rate for the uninspected portions of the pipeline was estimated using the TPD hit rate for the inspected portions as it was assumed that the third-party excavation activity rate was constant at all locations along the pipeline.

DOC has been shown to be a predominant factor that influences the hit rate from TPD. As such, a DOC adjustment factor is used as a multiplicative term that is applied on an estimate of hit frequency at a system mean depth of 1.5 m.

To calculate the average hit rate per km.yr, the counts of dents suspected to be caused by TPD were first normalized based on the DOC at which they were found by applying the inverse of the DOC adjustment factor as shown in Table 3.7. This has the effect of normalizing the number of dents (and by extension, the resulting hit rate) to a system mean depth of 1.5 m, which allows for the average hit rate calculated from these counts to take into account the DOC for the remainder of the pipeline using the DOC adjustment factor.

Table 3.7: Normalized Dents by Inspection

Inspection	Length Inspected (km)	Dents	Normalized Dent Count
S1	0.337	1	0.71
S2	1.154	1	0.57
S3	0.960	1	0.49
Total	**2.451**	**3**	**1.77**

3.2.1.3 Estimated Hit Rate for Full Pipeline

To estimate the hit rate for the NPS 12 Martin Grove pipeline, the normalized dent count was divided by the number of km-years of pipeline service (i.e., pipeline exposure) of the inspected portions. The average hit rate for the full pipeline without considering DOC data along the pipeline is calculated as 1.06E-02 per km.yr. When considering the DOC, the average hit rate is 1.42E-02 per km.yr. Details are shown in Table 3.8.

Table 3.8: Average Hit Rates for Full Pipeline

Total Normalized Dent Count of Inspected Portions	Exposure of Inspected Portions (km.yrs)	Average Hit Rate per km.yr (Non-Adjusted for DOC)	Average Hit Rate per km.yr (Adjusted for DOC)
1.77	166.88	1.06E-02	1.42E-02

3.2.2 Probability of Damage, Given a Hit

The probability of damage given an excavator strike was estimated using a structural reliability model that estimates the impact force of the strike and the pipeline's structural resistance to damage. Impact force and pipe resistance were modelled as random variables that account for the uncertainty in pipeline characteristics (e.g., wall thickness, ultimate tensile strength (UTS), Charpy toughness, etc.), as well as the uncertainty in load from the excavator.

Puncture and gouged dent modes of failure were considered in the probability of damage assessment, and a simplifying (but not necessarily conservative) assumption was made that both failure modes are predicted to result in large leak failure, corresponding to the Annex O ULS category. More details on the assessment can be found in Section 4.1.2 in the DIMP Risk Algorithm Document (RAD) [4]. The calculated probabilities of damage for each unique combination of pipe properties are shown in Table 3.9.

Table 3.9: Probability of Damage Based on Pipeline Properties

No.	% of Pipeline	NPS	MOP (psi)	Class Location	WT (mm)	Grade (MPa)	UTS (MPa)	2/3 CVN (J)	Probability of Damage
1	63%	12	175	3	6.35	207	414	10	6.41E-02
2	19%	12	175	3	6.35	207	414	20	3.56E-02
3	12%	12	175	3	6.35	290	414	20	3.61E-02
4	6%	12	175	3	6.35	359	455	20	3.33E-02
5	<1%	12	175	3	7.92	207	414	10	4.02E-02
6	<1%	12	175	3	6.35	290	414	10	6.17E-02

3.2.3 Third-Party Damage Failure Rate

The TPD large leak failure rate for the full pipeline was calculated by multiplying the average hit rate after adjusting for the DOC and the probability of damage, given a hit. The large leak rate was also converted into an equivalent rupture rate using Equation O.4 in CSA Z662-23 Annex O [2]. As a result, the estimated TPD large leak failure rate is 7.72E-04 per km.yr and the corresponding TPD equivalent rupture failure rate is 1.70E-05 per km.yr as shown in Table 3.10.

Table 3.10: TPD Large Leak and Equivalent Rupture Failure Rates

Length (km)	Large Leak Failure Rate per km.yr	Equivalent Rupture Failure Rate per km.yr
7.77	7.72E-04	1.70E-05

4. Tolerable Reliability Levels

4.1 Reliability Thresholds

The CSA Z662 Annex O standard provides guidance for operators to apply reliability-based thresholds to their pipeline systems for the LLS and ULS categories.

The LLS reliability threshold for natural gas pipelines is recommended to be 1.0E-03 per km.yr based on a combination of leak impact analysis, historical leak rates, and calibration to ASME B31.8 and CSA Z662 [2].

The ULS reliability threshold for natural gas pipelines is developed by considering the risk of natural gas ignited releases on human safety. The consequences of natural gas pipeline failure are proportional to the population density ρ, probability of ignition, and the hazard area; since the probability of ignition is approximately proportional to the diameter D, and hazard area is proportional to PD^2 where P is the pipeline pressure, the reliability thresholds are defined as an increasing function of ρPD^3. For an NPS 12 pipeline at 175 psi MOP in a Class 3 (urban) location, the ULS threshold is recommended to be 8.1E-05 per km.yr [2].

4.2 Segment Reliability

Failure rates for each individual 100 m segment are shown in Figure 4.1 and Figure 4.2 for the LLS and ULS categories, respectively, along with their respective limits and targets. The LLS limit and target have been set by adopting the Annex O LLS threshold as the limit (i.e., red line) and one order of magnitude lower than the limit as the target (i.e., green line). For ULS, the Annex O ULS threshold has been adopted as the limit and the Enbridge ULS threshold (1.0E-05 per km.yr) has been adopted as the target.

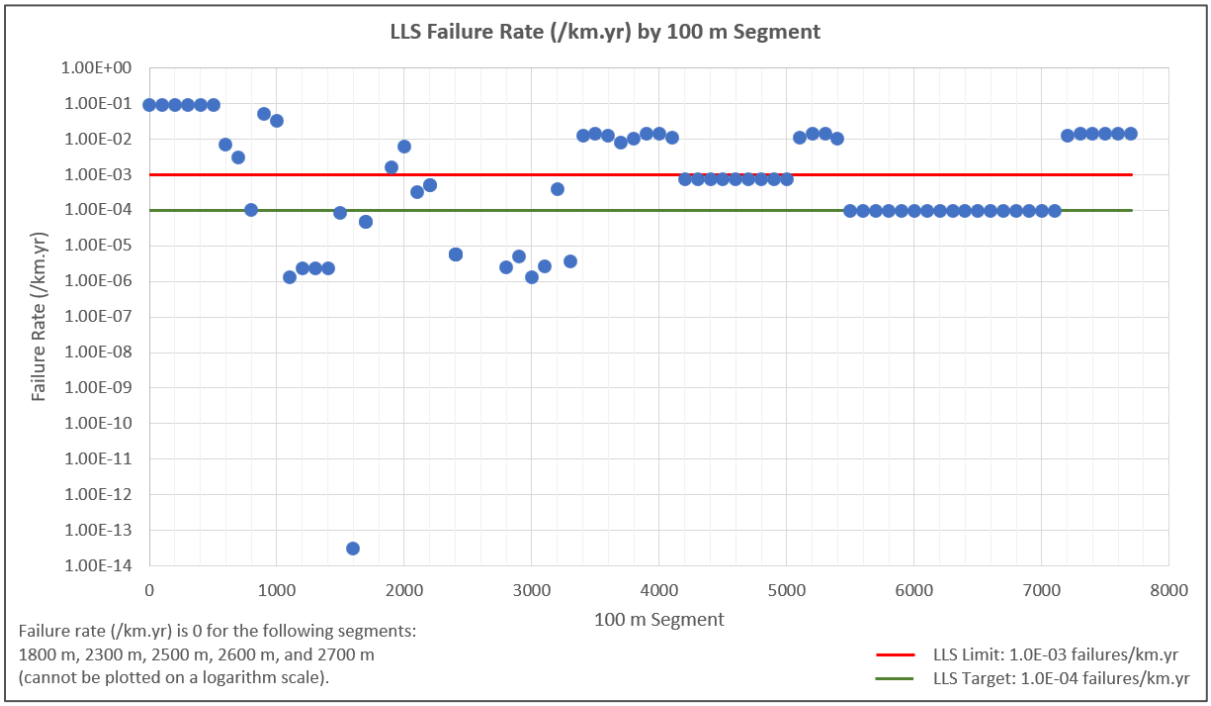


Figure 4.1: NPS 12 Martin Grove Pipeline - Annex O LLS Assessment

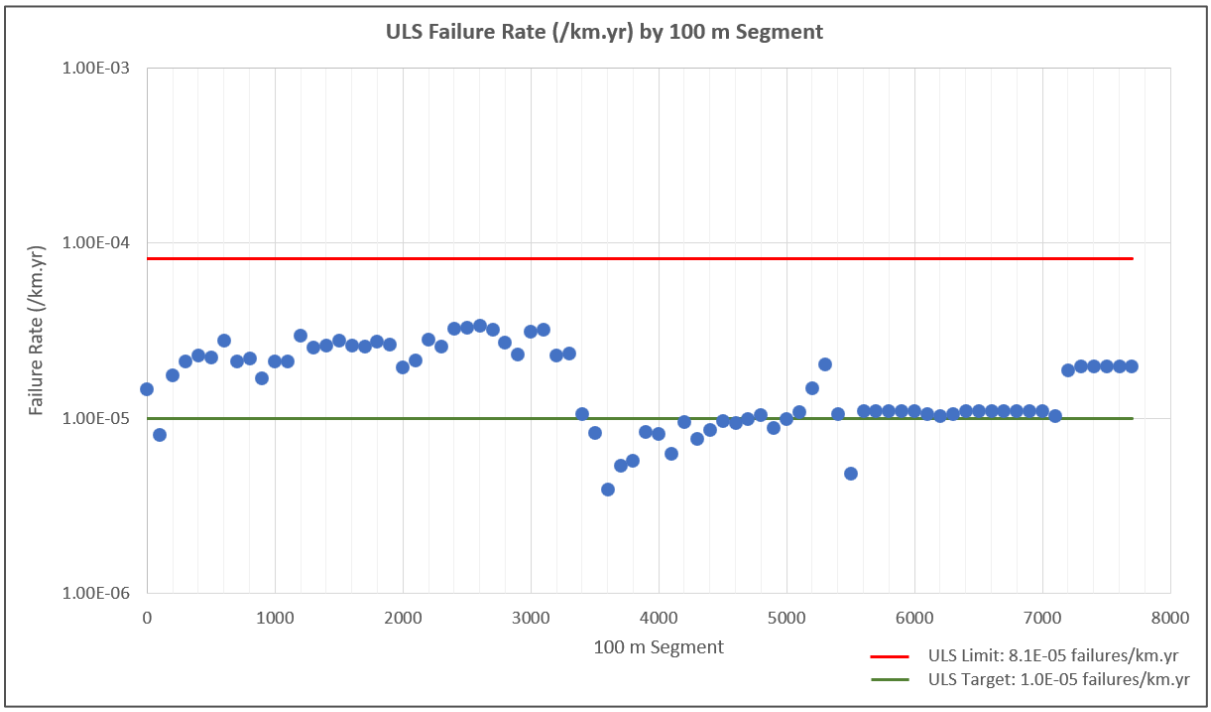


Figure 4.2: NPS 12 Martin Grove Pipeline - Annex O ULS Assessment

4.3 Reliability Maps

Figure 4.3 and Figure 4.4 show the reliability of the pipeline based on the LLS and the ULS, respectively, with 100 m segmentation granularity where the south end is considered the pipeline start (i.e., 0 m). Colouring has been applied based on each limit state's respective limit and target.

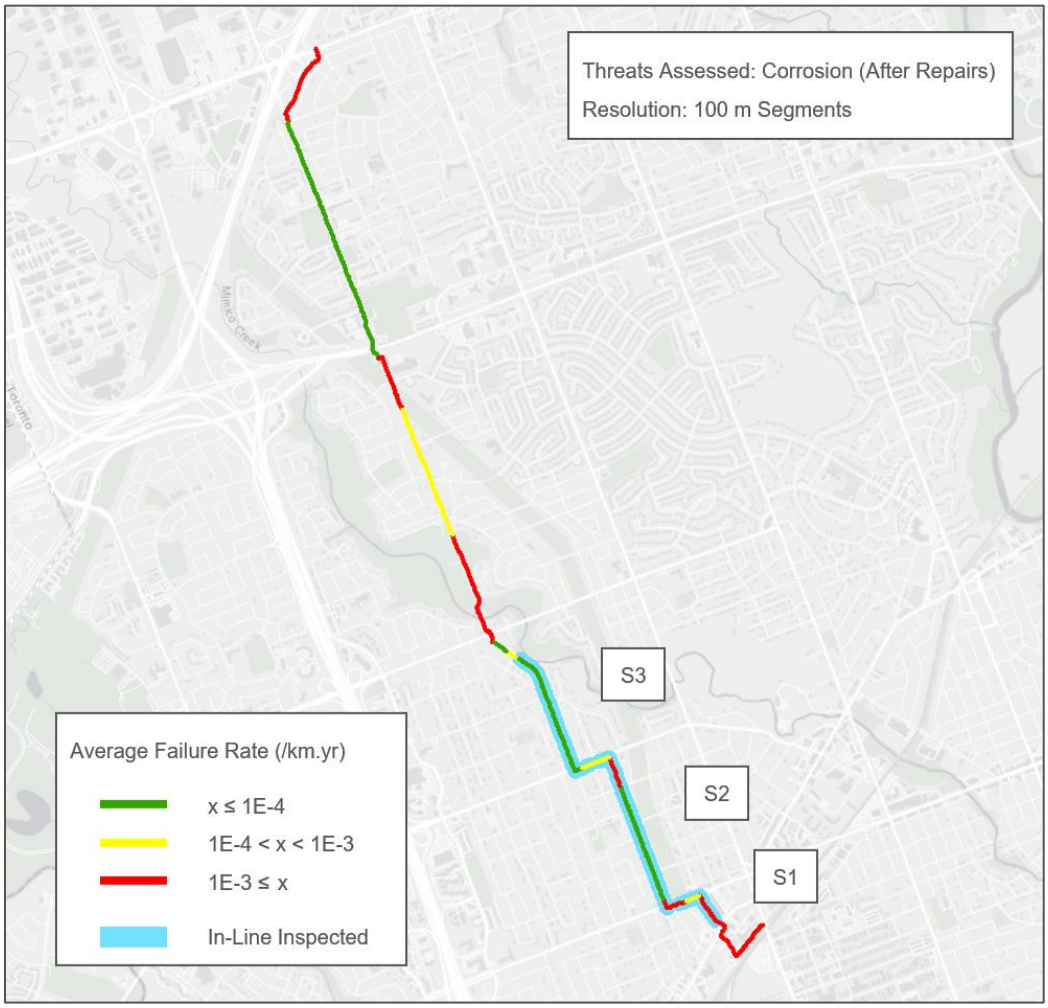


Figure 4.3: NPS 12 Martin Grove Pipeline - LLS Map (100 m Segments)



Figure 4.4: NPS 12 Martin Grove Pipeline - ULS Map (100 m Segments)

Figure 4.5 shows the overall reliability of the pipeline by combining the LLS and ULS categories as assessed against their respective limits and targets. The combined reliability map is coloured based on the worst-case reliability level from either the LLS or ULS map (i.e., “Above Limit” means that either the LLS or ULS limit was exceeded).



Figure 4.5: NPS 12 Martin Grove Pipeline - Combined LLS and ULS Map (100 m Segments)

Based on Figure 4.5, the safety level of six 100 m segments within the inspected portions is above the LLS or ULS limit as shown in Table 4.1.

Table 4.1: Inspected Segments with Safety Level Above Limit

100 m Segment	Inspection	Safety Level	Driving Threat	Drivers[1]
600 - 700 m	S1	Above Limit	Corrosion	Uninspected Portions
700 - 800 m	S1	Above Limit	Corrosion	ILI Anomalies: 187, 188 (103 should also be reviewed)
900 - 1000 m	S1	Above Limit	Corrosion	Uninspected Portions
1000 - 1100 m	S2	Above Limit	Corrosion	ILI Anomalies: 43 Uninspected Portions
1900 - 2000 m	S2	Above Limit	Corrosion	ILI Anomalies: 456
2000 - 2100 m	S2	Above Limit	Corrosion	ILI Anomalies: 562

[1] The depth measurements for ILI anomalies 103, 456, and 562 are within a tolerance of ± 20%.

5. Enbridge Operational Risk Assessment Matrix Mapping

The Enbridge Operational Risk Assessment Matrix (see Figure 5.1) was applied to the assessment of scenarios that could result in health and safety impacts to the public, customer disruption, or financial losses. The application of the risk matrix was performed by leveraging the assessed reliability in Section 3 with additional conditional probabilities that a given outcome will occur and potential consequences resulting from the scenario. The consequences were determined by consulting with SMEs and incorporating data-driven models, where available. The full scope of the NPS 12 Martin Grove pipeline (7.77 km) was applied in mapping the scenarios to the risk matrix.

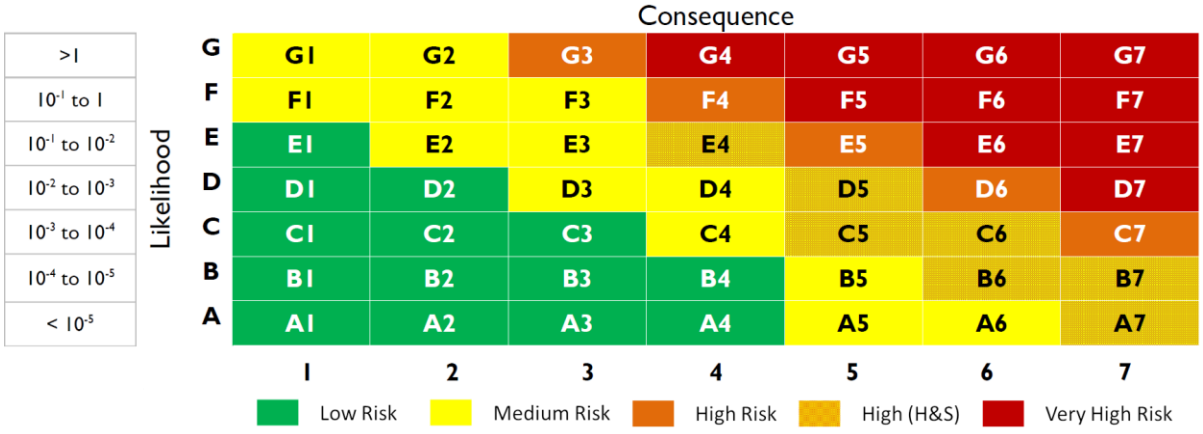


Figure 5.1: Enbridge Operational Risk Assessment Matrix

5.1 Health & Safety Risk

5.1.1 Health & Safety Outcome 1 (HS1) - Migration and Explosion of Nearby Structure

Pipeline leaks may pose a significant health and safety risk if gas migrates into a nearby building and causes an explosion. In this scenario, an underground leak migrates through the soil or via below-ground infrastructure, reaches an enclosed area or structure, accumulates to ignitable gas concentrations, and encounters an ignition source.

Due to its proximity to multiple nearby buildings, in the event of a small or large leak, the NPS 12 Martin Grove pipeline is considered susceptible to gas migration and explosion.

5.1.1.1 HS1 Probability

The probability of a migration and explosion event was determined by multiplying the probability of failure by the conditional probability that the leak migrates into a nearby building and causes an explosion as shown in Table 5.1. The conditional probabilities of migration and explosion have been determined though a review of migration-related ignitions in the PHMSA incident repository and represent system-wide averages. Using system-wide averages resulted in unconservative estimates of migration and explosion probabilities as the NPS 12 Martin Grove pipeline is assessed to have a higher-than-average susceptibility based on the environment in which it operates (e.g., higher number of roadways and hard surfaces and longer periods of frozen soil in the regional climate, which prevent gas from being able to permeate to the surface). The full details of the approach to determine condition probabilities of migration and explosion are outlined in Section 5.1.1 in the DIMP RAD [4]. The probability of a migration and explosion event on the NPS 12 Martin Grove pipeline is 1.80E-05 events/yr.

Table 5.1: Probability of Migration and Explosion

Threat	Probability of Migration and Explosion Given a Failure (Industry Average for Steel Mains)	Probability of Failure (/yr)	Probability of Migration and Explosion (/yr)
Corrosion (Small Leak)	1.79E-04	8.70E-02	1.56E-05
TPD (Large Leak)	4.09E-04	6.00E-03	2.45E-06
Total			**1.80E-05**

5.1.1.2 HS1 Consequence

The NPS 12 Martin Grove pipeline is considered to have high possible health and safety consequences as the pipeline traverses a highly urban location and is in proximity to many residential, commercial, and office buildings. Based on building footprints sourced from public datasets (OpenStreetMap and Microsoft Bing Maps), there are 773 buildings within 75 m of the pipeline in which a migration and explosion event is possible [5] [6]. The consequences due to health and safety are qualitatively estimated based on its location and Section 5.3.1 in the DIMP RAD and are shown in Table 5.2 [4].

Table 5.2: Fatality Risks of a Migration and Explosion Event

Estimate	Fatality	Justification
Minimum	0.5	The minimum fatality consequence assumes an explosion in an unoccupied structure, likely only resulting in possible injuries.
Most Likely	1	The best estimate for fatality consequence for a mix of residential, multi-residential, and commercial structures.
Maximum	20	The maximum fatality consequence assumes a failure in a large office building, commercial building, or religious facility, or in a building that may take longer to evacuate, such as a school or health care setting.

5.1.2 Health & Safety Outcome 2 (HS2) - Local Ignition at Failure Site

Large leaks may also pose a significant health and safety risk through immediate or delayed ignition near the source of the failure. In this scenario, ignition may occur immediately if sufficient kinetic energy is present in the initial moment of burst, or after a slight delay until the gas encounters a nearby ignition source (e.g., excavation equipment). Both jet fires and flash fires have been observed in industry on distribution pipelines.

5.1.2.1 HS2 Probability

The probability of a local ignition event was determined by multiplying the probability of failure by the conditional probability that the large leak ignites as shown in Table 5.3. The probability of local ignition at the failure site can be estimated by calculating the expected mass flowrate of gas following failure described in Section 5.2 in the DIMP RAD and using the ignition probabilities for an urban release listed in the OGP Report 434-6.1 [4] [7]. The probability of a local ignition event on the NPS 12 Martin Grove pipeline is 7.14E-05 events/yr.

Table 5.3: Probability of Local Ignition

Threat	Release Rate (kg/s)	Probability of Local Ignition Given a Failure	Probability of Failure (/yr)	Probability of Local Ignition (/yr)
Large Leak	2.71	0.01	6.00E-03	7.14E-05
Total				**7.14E-05**

5.1.2.2 HS2 Consequence

The health and safety consequences of a local ignition event can vary from injuries to fatalities depending on the magnitude of the fire and the number and vulnerability of people present. Due to the highly urban location that the NPS 12 Martin Grove pipeline traverses through and Martin Grove Road being a key route for different modes of transportation (e.g., walking, bicycling, and driving), it is expected that a local jet fire event would pose a high health and safety risk to the public. These consequences are qualitatively estimated as shown in Table 5.4.

Table 5.4: Fatality Risks of a Local Ignition Event

Estimate	Fatality	Justification
Minimum	0.5	No fatalities and possible injuries.
Most Likely	1	The best estimate for fatality consequence assumes a failure with an exposed individual present (likely during excavation activities).
Maximum	10	The maximum fatality consequence assumes a failure affecting a highly populated area along the NPS 12 Martin Grove pipeline.

5.1.3 Health & Safety Risk - Operational Risk Assessment Matrix Mapping

The result of the assessed health and safety risk outcome for the full scope of the NPS 12 Martin Grove pipeline is shown in Figure 5.2.

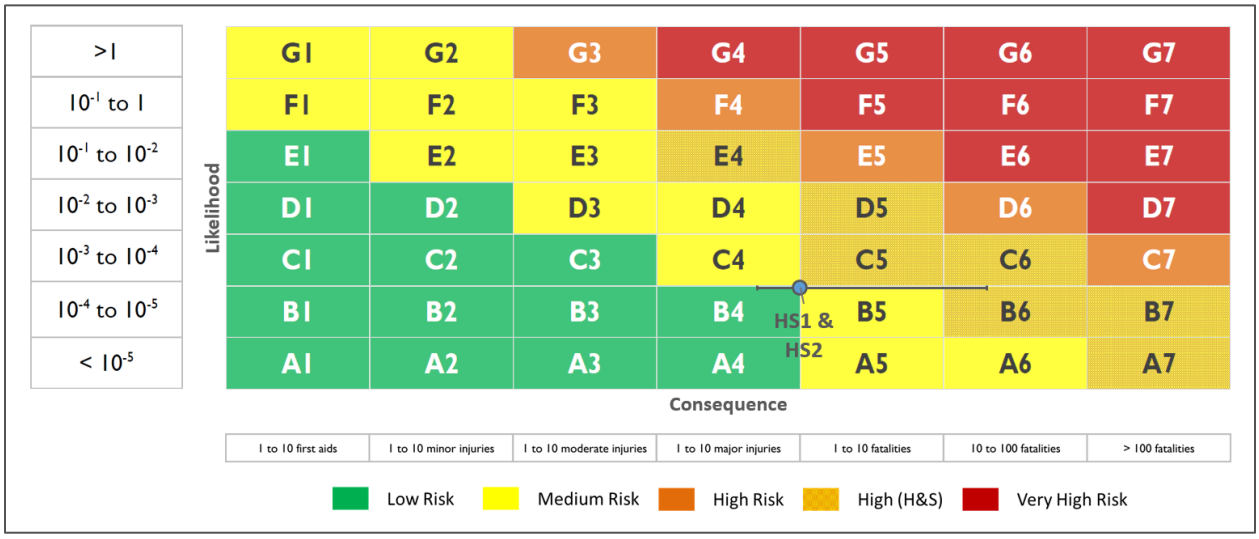


Figure 5.2: Enbridge Operational Risk Assessment Matrix - Health & Safety Risk

5.2 Operational Disruption Risk

5.2.1 Operational Disruption Outcome 1 (OD1) - Customer Losses Due to Operational Disruptions

In an emergency where a leak on a pipeline is confirmed, Enbridge's top priority is to perform "Make Safe" actions to protect its workers and the public from harm. Enbridge will also consider any possible environmental impacts of a large leak to ensure it meets its Environmental, Social, and Governance (ESG) commitments. Based on a case-by-case assessment, it may be required to perform an immediate isolation of the hazardous pipe segment by closing nearby valves or restricting the gas flow using a "squeeze-off" technique, resulting in potential customer loss.

5.2.1.1 OD1 Probability

The probability of an operational disruption event was determined by multiplying the probability of failure by the conditional probability that the failure would lead to an operational disruption as shown in Table 5.5. Conditional probabilities were based on SME judgement and industry data. The probability of an operational disruption event on the NPS 12 Martin Grove pipeline is 5.67E-03 events/yr.

Table 5.5: Probability of Operational Disruption

Threat	Probability of Operational Disruption Given a Failure	Probability of Failure (/yr)	Probability of Operational Disruption (/yr)
Small Leak	0.01	8.70E-02	8.70E-04
Large Leak	0.80	6.00E-03	4.80E-03
Total			**5.67E-03**

5.2.1.2 OD1 Consequence

Customers that are reliant on the NPS 12 Martin Grove pipeline system include those in residential and commercial buildings, who count on a reliable, dependable energy source for their daily operations. A review of gas demand has been completed to assess the customer impact of a service shutdown (i.e., isolation using mainline valves) on the NPS 12 Martin Grove pipeline for a range of scenarios including 0-degree day (summer), fall peak, and design day. In addition to the outside temperature, the location at which the failure occurs along the pipeline can impact the number of customer losses, resulting in a large range of possible outcomes. A qualitative assessment of the operational disruption consequences was completed by comparing the simulated customer loss scenarios with the business-unit specific operational disruption consequence criteria as shown in Table 5.6.

Table 5.6: Operational Disruption Customer Loss

Estimate	Customer Loss Consequence Category	Justification
Minimum	1	Isolation in the event of an emergency for a 0-degree day (summer) scenario.
Most Likely	3	Isolation in the event of an emergency for a fall peak scenario.
Maximum	5	Isolation in the event of an emergency for a design day scenario.

5.2.2 Operational Disruption Risk - Operational Risk Assessment Matrix Mapping

The result of the assessed operational disruption risk outcome for the full scope of the NPS 12 Martin Grove pipeline is shown in Figure 5.3.

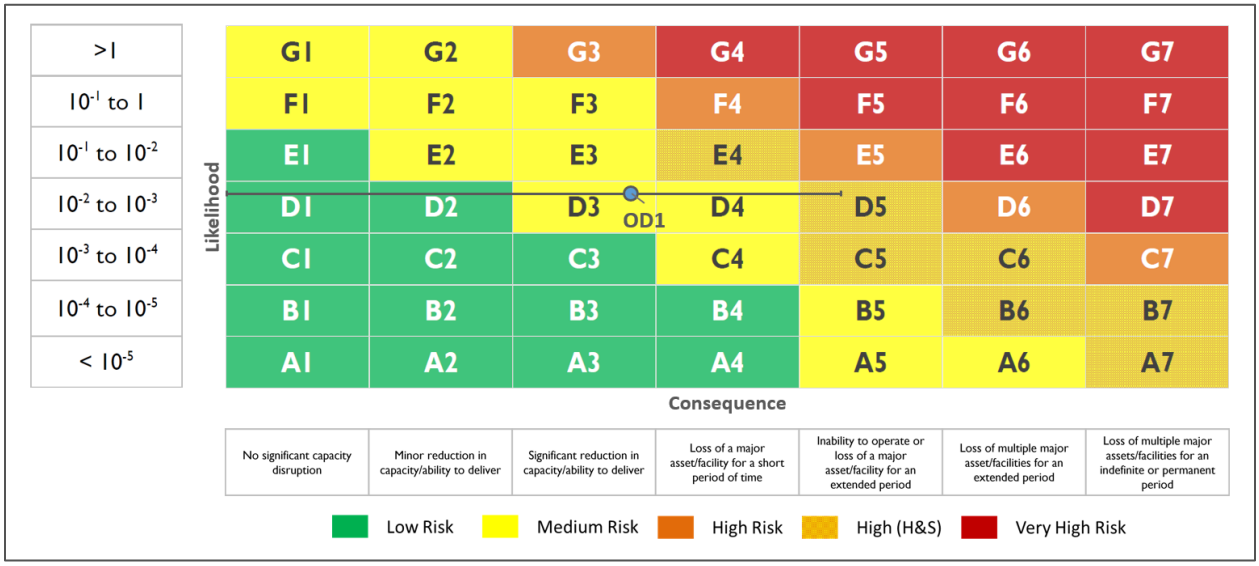


Figure 5.3: Enbridge Operational Risk Assessment Matrix - Operational Disruption Risk

5.3 Financial Risk

5.3.1 Financial Outcome 1 (F1) - Small Leak Resulting in Pipeline Repair or Replacement

The highest financial risk is associated with the scenario of a small leak on the NPS 12 Martin Grove pipeline where an immediate repair of the pipeline is necessary and will result in repair costs including planning, permitting, excavation, and materials. Given the immediate need for the repair, the emergency nature of the work will increase the costs in comparison to the same work completed on a planned basis due to expedited planning and permitting requirements and overtime work. In addition, timing of the repair cannot be planned to minimize gas demands, resulting in the possibility of performing a repair at a time of the year with high gas demands which requires installation of larger bypass piping (if bypass is possible) to mitigate any customer impacts.

5.3.1.1 F1 Probability

The probability of a pipeline repair is the product of the small leak failure rate and the total length of the pipeline, which is calculated to be 0.09 events/yr on the NPS 12 Martin Grove pipeline.

5.3.1.2 F1 Consequence

The costs associated with a repair of a small leak on the NPS 12 Martin Grove pipeline were determined through consultation with the pipeline's Engineering Construction Project Manager. The cost estimates were based on recent excavation, repair, and replacement projects on the NPS 12 Martin Grove pipeline as described in Section 3.1.2.1. However, using the costs of digs and repairs on a planned basis results in unconservative cost estimates as opposed to an emergency repair scenario.

Given that the costs of a leak can vary based on the repair type and if third-party contractors are involved, the consequences are presented as a range of values as shown in Table 5.7.

Table 5.7: Pipeline Repair Costs of Corrosion Leak

Estimate	Value ($)	Justification
Minimum	$120,000	Assumes the repair type is a recoat where the repair execution is completed internally and an internal gas pipeline inspector is used.
Most Likely	$185,000	Assumes the repair type is a pressure containment sleeve where the repair execution is completed by a third-party contractor and an internal gas pipeline inspector is used.
Maximum	$250,000	Assumes the repair type is a cut-out where the repair execution is completed by a third-party contractor and an external gas pipeline inspector is used.

5.3.2 Financial Risk - Operational Risk Assessment Matrix Mapping

The result of the assessed financial risk outcome for the full scope of the NPS 12 Martin Grove pipeline is shown in Figure 5.4.

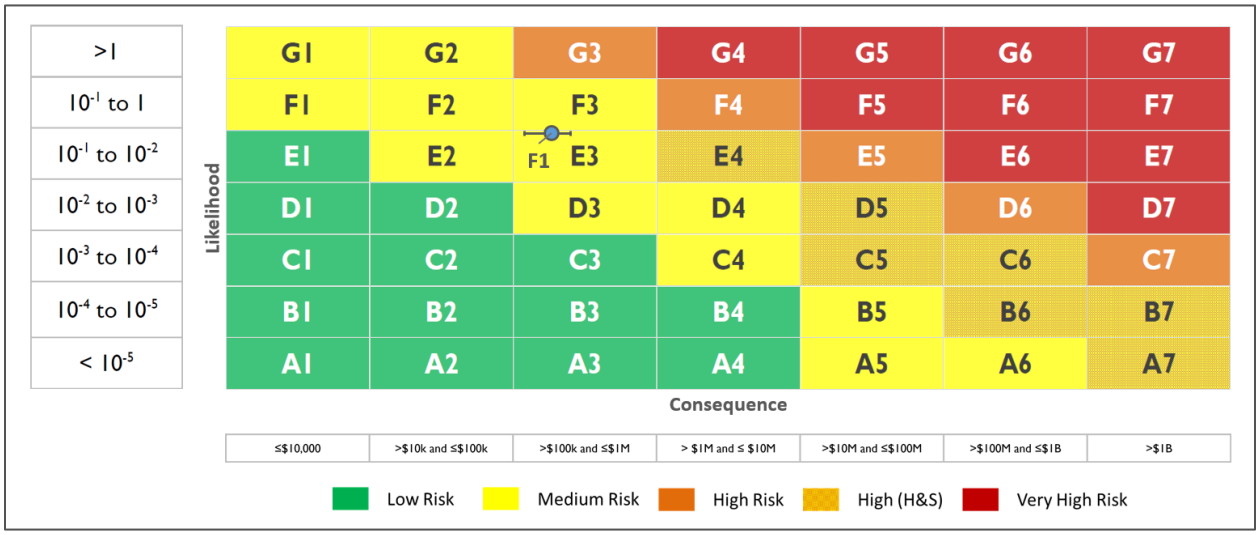


Figure 5.4: Enbridge Operational Risk Assessment Matrix - Financial Risk

5.4 Combined Operational Risk Assessment Matrix Plot

The most significant risks associated with a failure of the NPS 12 Martin Grove pipeline are overlayed in Figure 5.5. This mapping uses a combination of quantitative inputs and qualitative assessments to assess the risk based on the Enbridge Operational Risk Assessment Matrix. As such, various possible outcomes on the NPS 12 Martin Grove pipeline meet the enterprise Safety & Reliability Framework definition of “Medium Risk”. Notably, the best estimate for the health and safety risk outcome borders “High Risk” and has potential to meet “High Risk” under severe consequence scenarios.

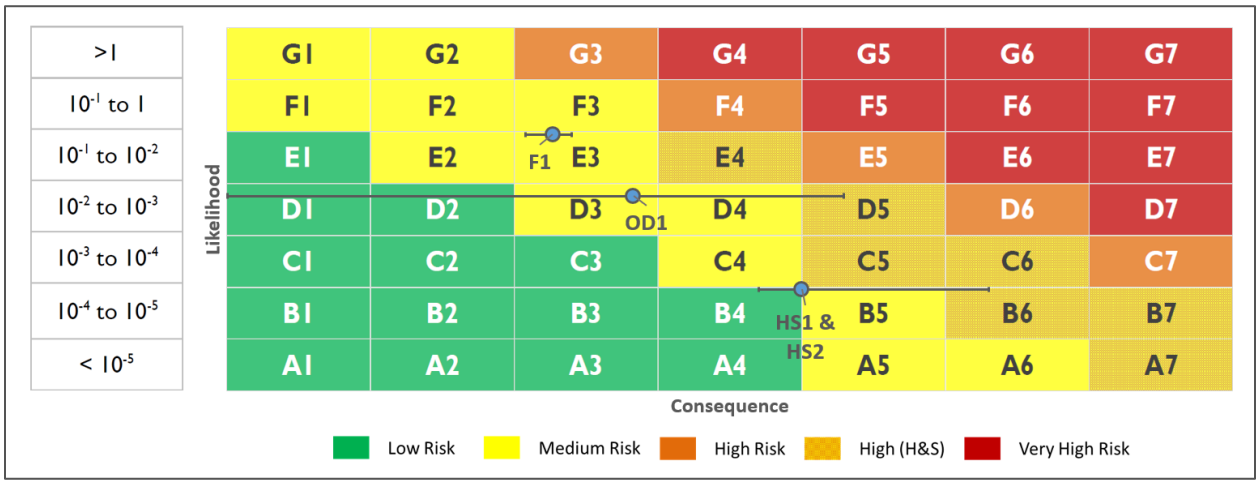


Figure 5.5: Enbridge Operational Risk Assessment Matrix - All Significant Outcomes

6. Recommendations

A risk assessment utilizing a defense-in-depth approach was conducted to evaluate the reliability and risk of the NPS 12 Martin Grove pipeline considering corrosion and TPD threats to its pipeline integrity.

Failure rates were calculated based on historical information and best practice reliability models and then compared to industry benchmarks. The assessment supports the following conclusions:

- 3.0 km of the 7.77 km pipeline (39%) is assessed to have a small leak failure rate above the 1.0E-03 per km.yr LLS limit described by CSA Z662 Annex O.
- 0 km of the 7.77 km pipeline (0%) is assessed to have a large leak (or equivalent rupture) failure rate above the 8.1E-05 per km.yr ULS limit described by CSA Z662 Annex O for an NPS 12 pipeline at 175 psi MOP in a Class 3 (urban) location.
- Integrating the LLS and ULS approaches, 3.0 km of the 7.77 km pipeline (39%) fails one or both reliability limits.

To take into account the overall risks of a failure on the pipeline system, the quantitative reliability assessment was supplemented with consequences of various outcomes and mapped to the Enbridge Operational Risk Assessment Matrix. This exercise concluded that various risk scenarios meet the Enbridge Operational Risk Assessment Matrix definition of “Medium Risk”. Notably, the best estimate for the health and safety risk outcome borders “High Risk” and has potential to meet “High Risk” under severe consequence scenarios.

In conclusion, it is determined that remedial action is required to improve the reliability of the NPS 12 Martin Grove pipeline.

References

[1] Enbridge Gas Inc., "Quantitative Risk Assessment (QRA) - St. Laurent North Pipeline (EB-2024-0200, Exhibit B, Tab 1, Schedule 1, Attachment 2)," Ontario Energy Board, 2024.

[2] Canadian Standard Association, "CSA Z662:23 Oil and Gas Pipeline Systems - Annex O Reliability-based design and assessment (RBDA) of onshore non-sour service natural gas transmission and LVP liquid hydrocarbon pipelines (CSA Z662:23)," CSA Group, 2023.

[3] Integrity Assessments Department - Enbridge Gas Transmission and Midstream, Enbridge Inc., "Asset Integrity Risk Algorithm Document (RAD)," 2023.

[4] Integrity Assessments - Enbridge Gas Distribution and Storage, Enbridge Inc., "PRIM Distribution Risk Model - Risk Algorithm Document," 2021.

[5] OpenStreetMap, "Ontario," Geofabrik, 2025. [Online]. Available: https://download.geofabrik.de/north-america/canada/ontario.html.

[6] Microsoft, "Canadian Building Footprints," Github, Inc., 2019. [Online]. Available: https://github.com/microsoft/CanadianBuildingFootprints.

[7] International Association of Oil & Gas Producers, "OGP Risk Assessment Data Directory - Ignition Probabilities (Report No. 434 – 6.1)," 2010.

Appendix A: Pipeline Characteristics Maps

Wall Thickness

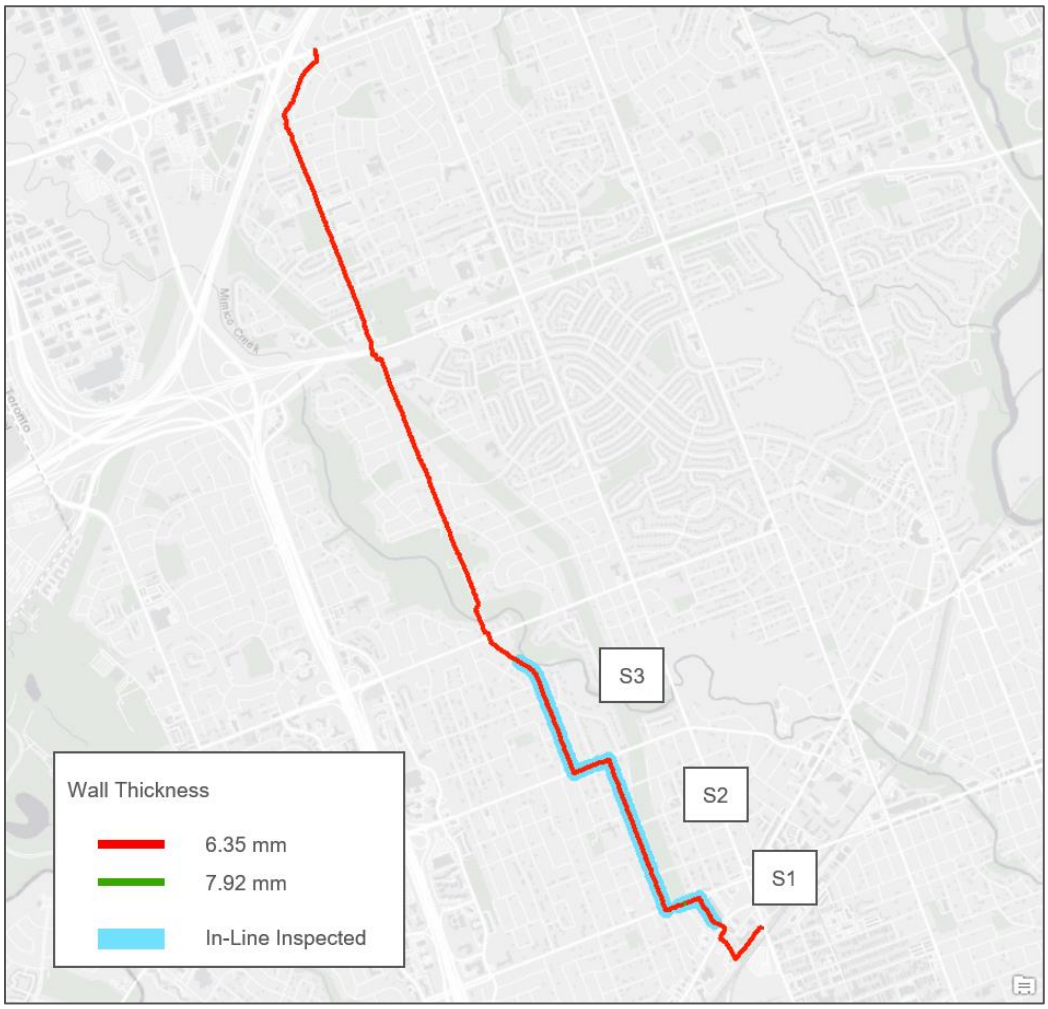


Figure A.1: NPS 12 Martin Grove Pipeline - Wall Thickness

Grade

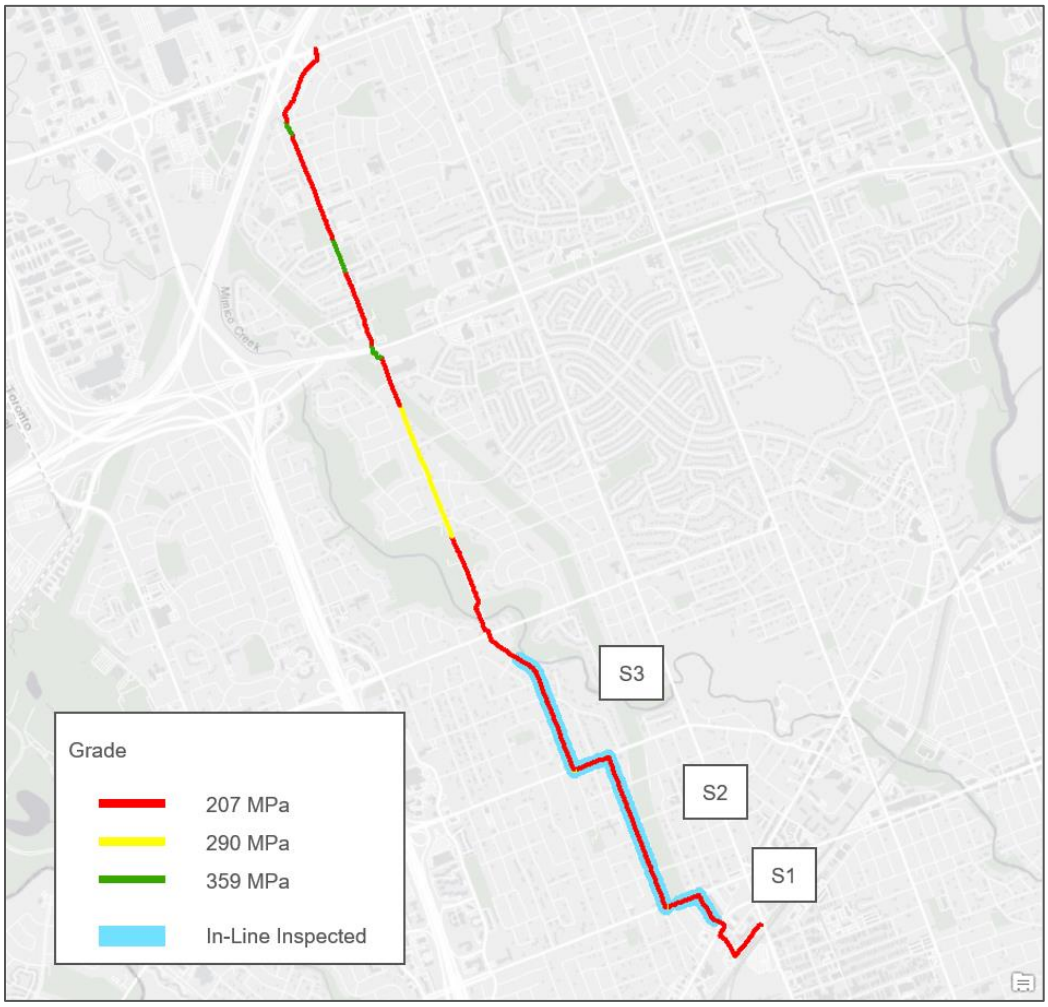


Figure A.2: NPS 12 Martin Grove Pipeline - Grade

Coating



Figure A.3: NPS 12 Martin Grove Pipeline - Coating

Install Year

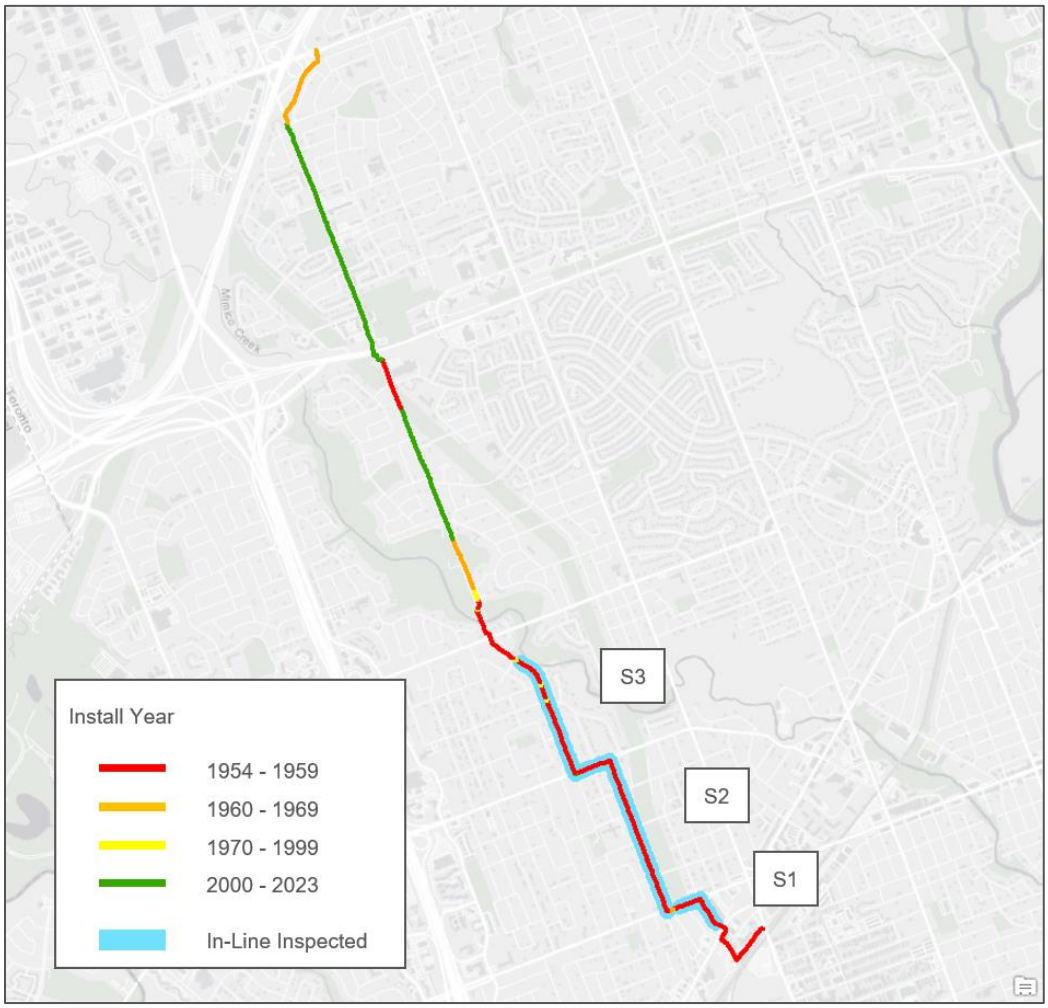


Figure A.4: NPS 12 Martin Grove Pipeline - Install Year

Corrosion Area



Figure A.5: NPS 12 Martin Grove Pipeline - Corrosion Area

NPS 10 Sarnia South Pipeline - Quantitative Risk Assessment (QRA)

October 16, 2025

ENBRIDGE

Integrity Assessments & Risk

Integrity Department

Document Governance

Revision History

Date	Version	Prepared By	Approved By
2025-10-16	1.0	Carly Li Engineer in Training II, Integrity Assessments & Risk, Pipelines & Storage	Kai Ji, P.Eng. Supervisor, Integrity Assessments & Risk, Pipelines & Storage Hooman Zahedi, P.Eng. Manager, Risk Assessments

1. Introduction

The NPS 10 Sarnia South pipeline was identified as a 2024 EDIMP priority pipeline and in-line inspections (ILIs) were performed in 2024 to assess the condition of the line.

Subsequently, a Quantitative Risk Assessment (QRA) has been conducted to assess the risk of the NPS 10 Sarnia South pipeline. Methodologies used in the QRA are similar to those used in the St. Laurent Pipeline (SLP) Replacement Project [1]. This report summarizes the QRA performed, and the results will be utilized to develop long-term risk mitigation plans for the NPS 10 Sarnia South pipeline.

2. Background Information

2.1 Pipe Properties

The pipeline characteristics that comprise the majority of the NPS 10 Sarnia South pipeline are shown in Table 2.1. A portion of the line within the Thames River was abandoned in 2022 and as such, the pipeline has been split into NPS 10 Sarnia South A (south of the river) and NPS 10 Sarnia South B (north of the river). A detailed breakdown of the complete pipeline characteristics can be found in Appendix A: Pipeline Characteristics Maps.

Table 2.1: Primary Pipeline Specifications

Attribute	Specification	Assumptions
NPS	10	
Length	60.53 km (A - 20.91 km, B - 39.62 km)	
Install Year	1946 (Majority - 45.7%), 1937 or 1938 (Oldest - 26.2%)	
MOP	200 psi	
Wall Thickness	5.56 mm or 7.09 mm	Assumed based on NDE reports and company records.
Grade	172 MPa	Assumed based on CSA Z662-23 Clause 5.6.4 [2].
Coating	Bare or Coal Tar	Assumed based on 2024 integrity digs and pipe vintage.
% SMYS	19.7%	Based on assumed values.

2.2 Inspection

2.2.1 Coverage

ILI runs across five launch sites were completed at various locations along the NPS 10 Sarnia South pipeline using the Intero Pipe Explorer 10-MFL-A/LDS inspection tool in 2024. The ILIs captured condition data on 4.49 km (7.42%) of the pipeline. The inspection extents and locations are shown in Figure 2.1.

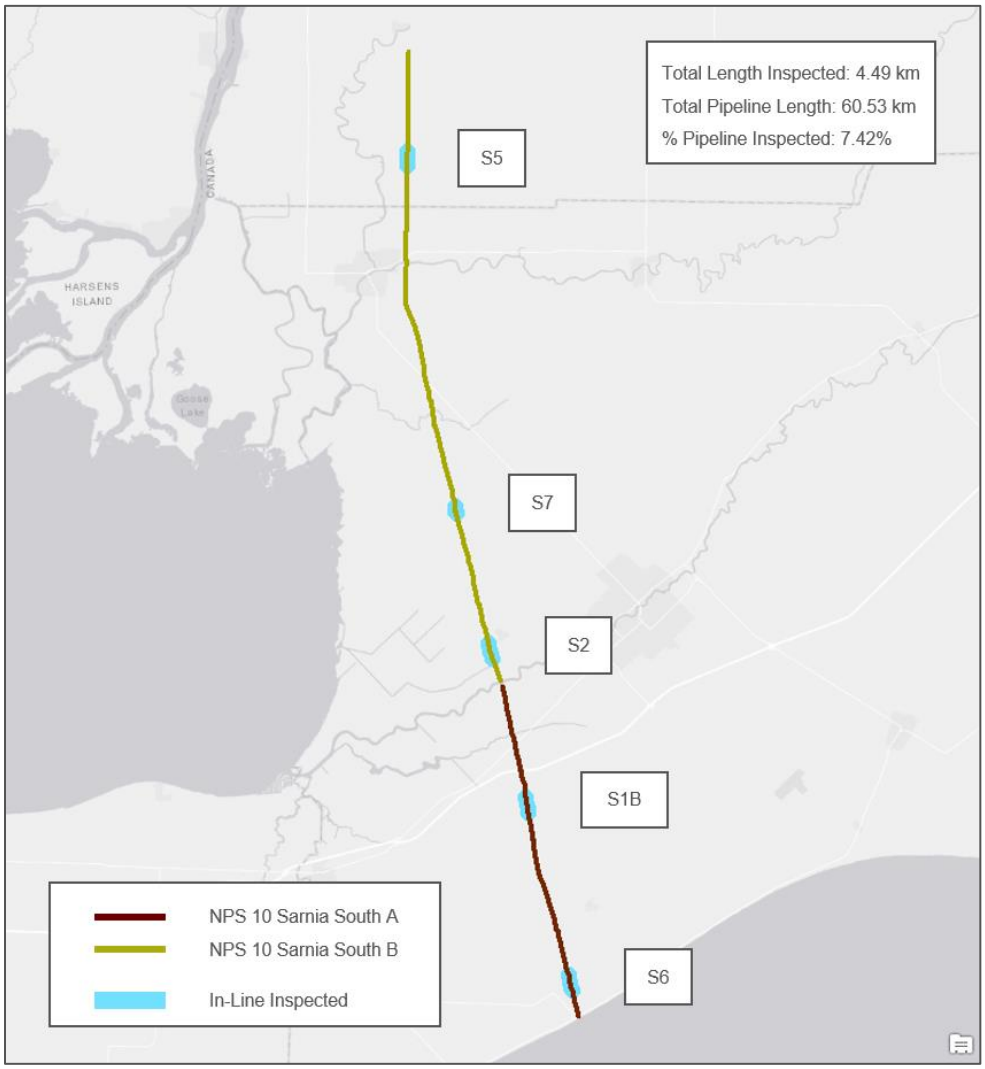


Figure 2.1: Crawler Inspection Extents and Locations

2.2.2 Metal Loss Results (MFL Technology)

A total of 17,151 metal loss features above the reporting threshold were reported along the inspected portions of the pipeline. 3 individual anomalies were identified with metal loss greater or equal to 70% wall loss (Phase 1). The number of reported metal loss features by inspection and the resulting feature densities are shown in Table 2.2.

Table 2.2: Reported Metal Loss Features by Inspection

Inspection	Length Inspected (km)	Metal Loss Count	Features / km
S6	1.018	365	358.6
S1B	1.019	3,194	3,134.1
S2	1.041	1,665	1,600.0
S7	0.519	8,853	17,044.6
S5	0.897	3,074	3,428.1
Total	**4.494**	**17,151**	**3,816.7**

As shown in Figure 2.2, metal loss counts were dominated by features found on S7 which also exhibited higher corrosion density than the other inspections.

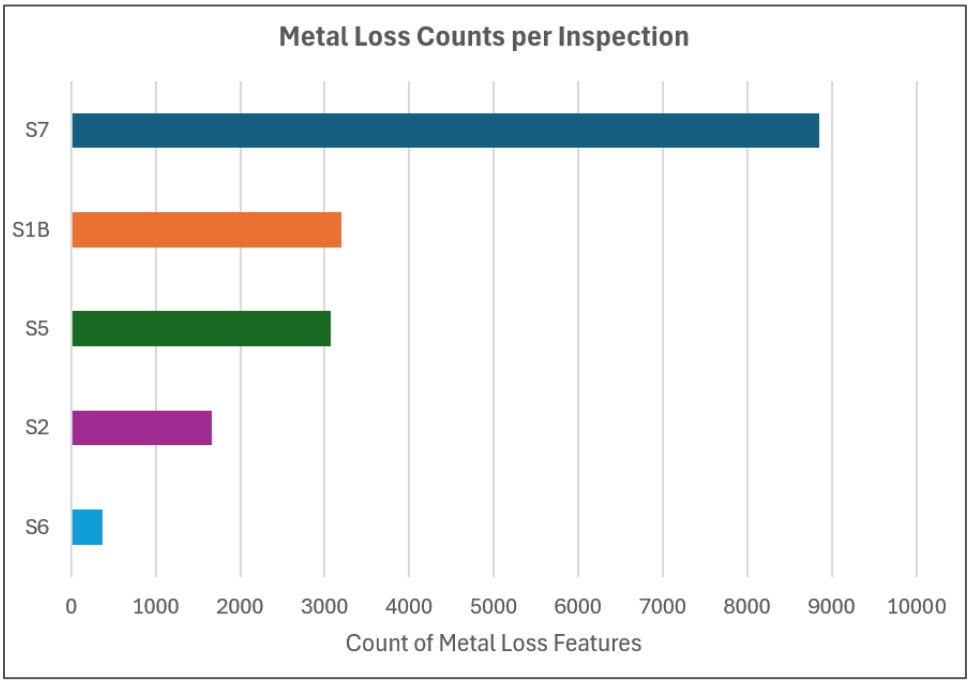


Figure 2.2: Metal Loss Counts per Inspection

The counts of corrosion depths reported by inspection are shown in Table 2.3, Figure 2.3, and Figure 2.4.

Table 2.3: Metal Loss Depths per Inspection

Depth (%) - Bin	S6	S1B	S2	S7	S5
10	350	3,004	1,633	7,878	3,011
20	15	132	11	809	38
30	0	30	18	137	22
40	0	17	3	21	1
50	0	8	0	6	2
60	0	1	0	1	0
70	0	2	0	1	0

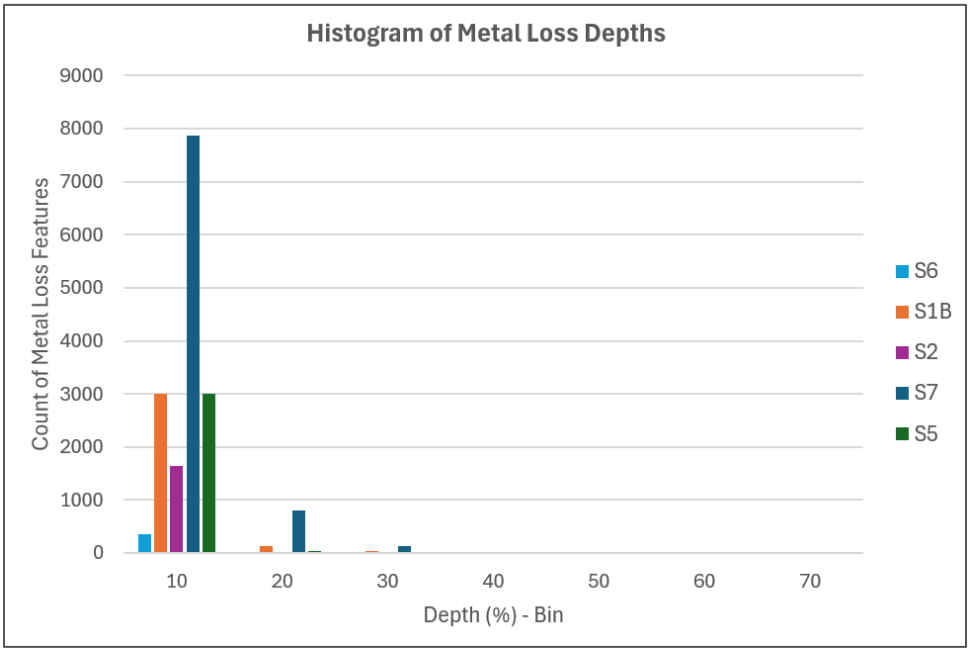


Figure 2.3: Histogram of Metal Loss Depths

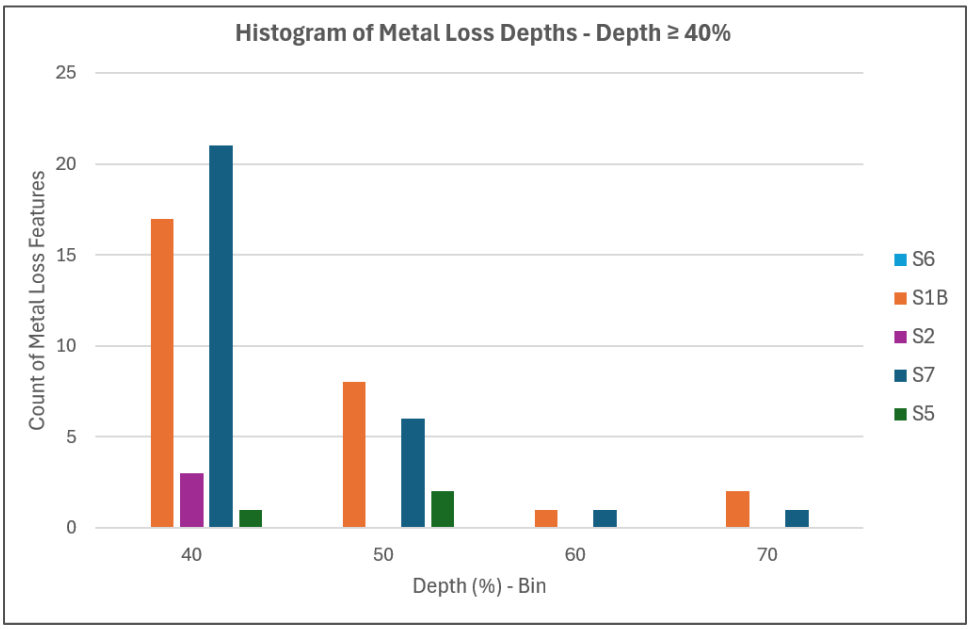


Figure 2.4: Histogram of Metal Loss Depths - Depth ≥ 40%

2.2.3 Deformation Results (LDS Technology)

A total of 110 dent features above the reporting threshold were reported along the inspected portions of the pipeline as shown in Table 2.4.

Table 2.4: Reported Dents by Inspection

Inspection	Length Inspected (km)	Dent Count	Dents / km
S6	1.018	18	17.7
S1B	1.019	32	31.4
S2	1.041	31	29.8
S7	0.519	18	34.7
S5	0.897	11	12.3
Total	**4.494**	**110**	**24.5**

Of the dents reported, 71 (65%) were reported as top-side (above the 4 and 8 o'clock positions). In addition, 18 dents had a depth greater than 2% of the pipeline outer diameter and 0 dents were identified as interacting with metal loss. The details of the more significant dents separated by inspection are shown in Table 2.5.

Table 2.5: Significant Dents by Inspection

Inspection	Top-side Dents	Dents > 2%	Dents with Metal Loss
S6	13	1	0
S1B	23	7	0
S2	15	2	0
S7	13	7	0
S5	7	1	0
Total	**71**	**18**	**0**

2.2.4 Compression Couplings

A total of 411 compression couplings were found along the inspected portions of the pipeline as shown in Table 2.6. Of the 411 compression couplings, 369 (90%) were reported as unrestrained by the ILI tool.

Table 2.6: Reported Compression Couplings by Inspection

Inspection	Length Inspected (km)	Count of Compression Couplings	Compression Couplings / km
S6	1.018	82	80.6
S1B	1.019	84	82.4
S2	1.041	82	78.8
S7	0.519	86	165.6
S5	0.897	77	85.9
Average	**4.494**	**411**	**91.5**

3. Reliability

The reliability of the NPS 10 Sarnia South pipeline was quantitively assessed by evaluating the line's susceptibility to corrosion and third-party damage (TPD) threats with potential to cause a loss of containment (LoC) failure.

There are multiple modes which a LoC can occur and are categorized by three release sizes:

- Small Leak
- Large Leak
- Rupture

CSA Z662 Annex O further categorizes the modes into two distinct Limit State categories [2]:

- Leakage Limit State (LLS)
- Ultimate Limit State (ULS)

Definitions can be found in Section 3.1 in the SLP QRA [1].

3.1 Corrosion Threat

3.1.1 Reliability Based on Historical Leaks

A statistical reliability assessment approach was used by observing the pipeline's leak history and considering a plausible set of ranges for the historical corrosion leak rate as shown in Table 3.1. For the NPS 10 Sarnia South pipeline, the average historical corrosion leak rate is calculated to be 3.67E-03 per km.yr based on available leak record history. Applying a Poisson distribution of incidence rates at 95% confidence results in extended confidence bounds, and failure rates above these bounds are plausible as the Poisson distribution assumes that events occur randomly whereas the corrosion threat is known to increase with time.

Table 3.1: Average Historical Corrosion Leak Rate using Leak Record History

Term	Value
Number of Corrosion Leaks on Pipeline	1. 2021 leak due to corrosion 2. 2024 leak due to corrosion
Length of Pipeline	60.53 km
Time Period	9 years (2016 to 2024)
Average Historical Corrosion Leak Rate	3.67E-03 per km.yr
Average Historical Corrosion Leak Rate with 95% Confidence Interval	4.45E-04 per km.yr to 1.33E-02 per km.yr

3.1.2 Reliability Based on Inspection Data

3.1.2.1 Reliability for Inspected Portions

After the inspections, Enbridge Gas Ontario completed multiple repairs to mitigate Phase 1 anomalies as shown in Table 3.2.

Table 3.2: Completed Repairs

Inspection	Repair	Location
S1B	Composite Reinforcement Sleeve, Atlas Wrap (~5m)	5834 6 Line West
	Composite Reinforcement Sleeve, Atlas Wrap (~5m)	5834 6 Line West
S7	Composite Reinforcement Sleeve, Atlas Wrap (~3m)	7260-8008 St. Philippes Line

A structural reliability model was used to calculate the reliability of the pipeline's inspected portions based on the reported ILI corrosion features by applying the ASME Modified B31G failure criterion and a Probability of Exceedance (POE) approach. As such, the average corrosion (small leak) failure rates along the inspected portions are calculated to be 1.68E-03 per km.yr before the repairs and 2.85E-05 per km.yr after the repairs as shown in Table 3.3.

Table 3.3: Average Corrosion Failure Rates for Inspected Portions Before and After Repairs

Inspection	Length Inspected (km)	Average Corrosion Failure Rate per km.yr (Before Repairs)	Average Corrosion Failure Rate per km.yr (After Repairs)
S6	1.018	6.81E-06	6.81E-06
S1B	1.019	5.21E-03	9.76E-05
S2	1.041	7.71E-08	7.71E-08
S7	0.519	4.27E-03	1.06E-05
S5	0.897	1.79E-05	1.79E-05
Average	**4.494**	**1.68E-03**	**2.85E-05**

3.1.2.2 Reliability for Uninspected Portions

3.1.2.2.1 Older Pipe Vintages

To estimate the corrosion condition for the rest of the pipeline, ILI results before repairs from the 4.49 km of inspections were extrapolated to uninspected segments using a like-in-kind approach. The like-in-kind approach involves defining "like" segments of the pipeline which are considered to have similar key characteristics that are known to influence corrosion.

Factors such as the pipe body coating and corrosion area (i.e., areas defining continuous cathodic protection) were considered for defining the appropriate like-in-kind segments. However, the majority of the pipeline shares one corrosion area (over 99%) and thus, the like segments were defined based on the coating. For segments with unknown coating (approximately 93%), it was assumed that pipe installed in the 1930s and 1940s was bare or coated with coal tar, pipe installed in the 1950s and 1960s was coated with coal tar, and pipe installed in the 1970s and after was coated with PE.

Since inspection data were primarily collected for pipe installed between 1937 and 1946 (over 97%), the conditions of the corresponding segments were only considered representative for older pipe vintages. The like-in-kind approach was therefore only applied to pipe installed before 1970. As the majority of the pipeline shares one coating, this resulted in one like-in-kind grouping that consists of pipe installed before 1970.

Additionally, for pipe installed before 1970, approximately 46% of the wall thickness is known (data sources include ILI, NDE, and GIS) while 54% remains unknown. Of the known data, about 91% of the pipe segments has a wall thickness of 7.09 mm and the remaining 9% is primarily 5.56 mm. Thus, for pipe segments with unknown wall thickness, the same distribution is assumed. This approach was used to provide a more representative estimate based on available data as wall thickness is a primary factor influencing corrosion.

The failure rate for each uninspected segment was calculated by following the same calculation as described for the inspected portions using the estimated defect severity and defect density:

- Defect severity: A distribution of metal loss depth growth rates for uninspected segments was generated using a simulation technique that sampled (“Bootstrapped”) the metal loss depth growth rates from the inspected portions. It was sampled 10 million times to ensure representation across the entire population of discovered defects.
- Defect density: The feature count per kilometre for uninspected segments was taken directly from the inspected portions.

Since the approach involves extrapolating condition rather than the failure rate estimate outright, segments with stronger mechanical properties (e.g., thicker walls) were credited with higher reliability.

3.1.2.2.2 Modern Pipe Vintages

As inspection data for more modern pipe was limited, for pipe installed in 1970 and after, the corrosion failure rate was estimated using PIRAMID™ developed by C-FER Technologies, a historical-based reliability analysis method that utilizes threat-specific calibrated factors to update a baseline failure rate to account for pipeline-specific properties [3]. In this case, the baseline corrosion failure rate was determined using Enbridge Gas Ontario failure data for distribution steel mains. Modification factors included wall thickness, coating type, vintage, and soil corrosivity, as they influence the development, growth, and severity of corrosion on a pipeline.

3.1.2.2.3 Pipeline Groupings

Table 3.4 and Figure 3.1 depict the groupings for estimating corrosion reliability of the NPS 10 Sarnia South pipeline.

Table 3.4: Pipeline Groupings

Type	Group	Coating	Length (km)	% of Total Pipeline Length
Uninspected: Older pipe (1937 - 1969)	1	Bare or Coal Tar	49.96	82.5%
Uninspected: Modern pipe (1970 - present)	2	PE	6.07	10.0%
Inspected	3	Bare, Coal Tar, or PE	4.49	7.4%

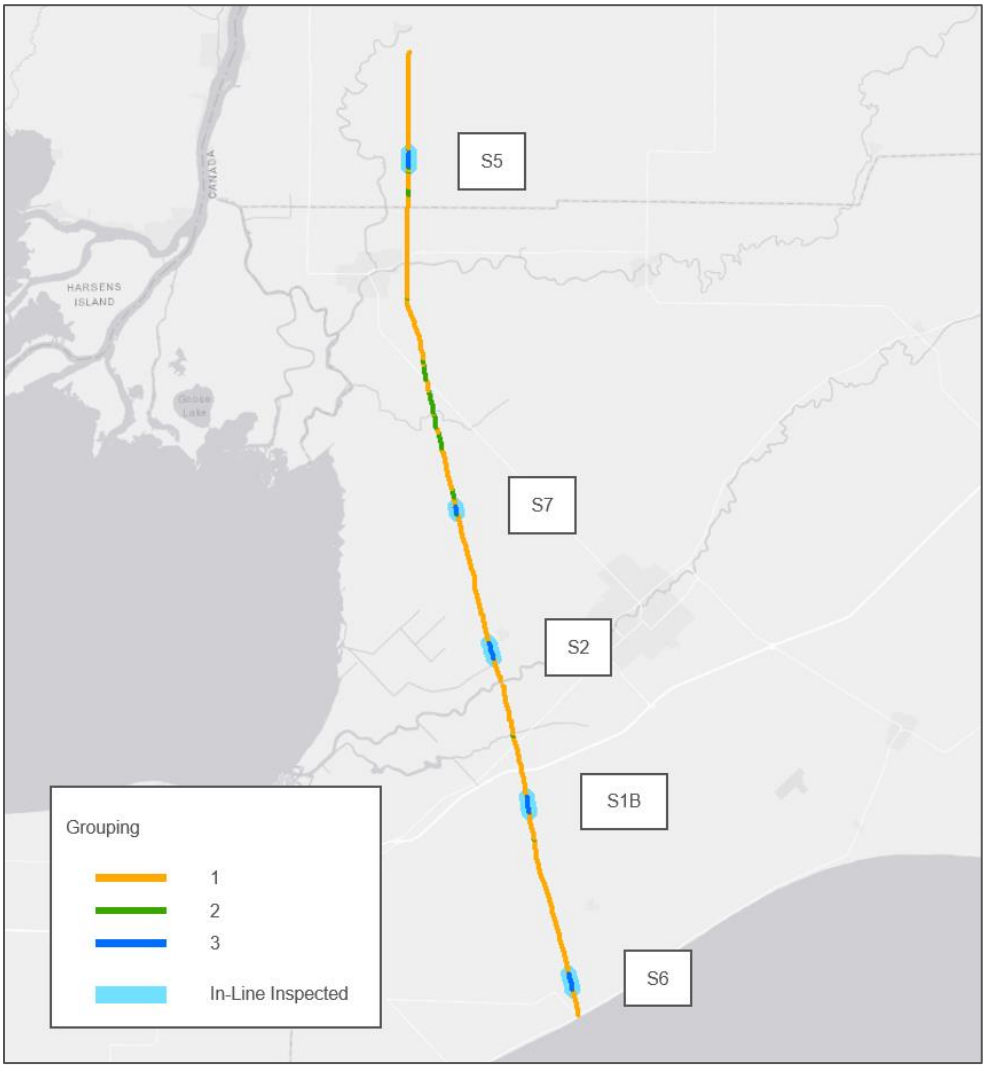


Figure 3.1: Pipeline Groupings with ILI Locations Overlaid

3.1.2.3 Reliability for Full Pipeline

The total pipeline is estimated to have an average corrosion (small leak) failure rate of 4.31E-03 per km.yr based on the inspection data extrapolated to the uninspected portions. The calculated average failure rates for the inspected and uninspected portions are summarized in Table 3.5.

Table 3.5: Summarized Corrosion Reliability Results

Pipeline	Length (km)	Average Failure Rate per km.yr (Before Repairs)	Average Failure Rate per km.yr (After Repairs)
Inspected Portions	4.49	1.68E-03	2.85E-05
Uninspected Portions	56.03	4.65E-03	4.65E-03
Total	**60.53**	**4.43E-03**	**4.31E-03**

3.2 Third-Party Damage Threat

The NPS 10 Sarnia South pipeline is vulnerable to TPD caused by farming equipment or excavators as it traverses the tilled land of farm fields or is within the road ROW, respectively, as shown in Table 3.6 and Figure 3.2.

Table 3.6: Land Type and TPD Threat

Chainage (km)	Length (km)	% of Length	Land Type	Threat
0.0 km to 20.906 km and 21.2211 km to 45.5527 km	45.24	75%	Tilled	TPD - Farming Equipment
45.5527 km to 60.8426 km	15.29	25%	Road ROW	TPD - Excavator

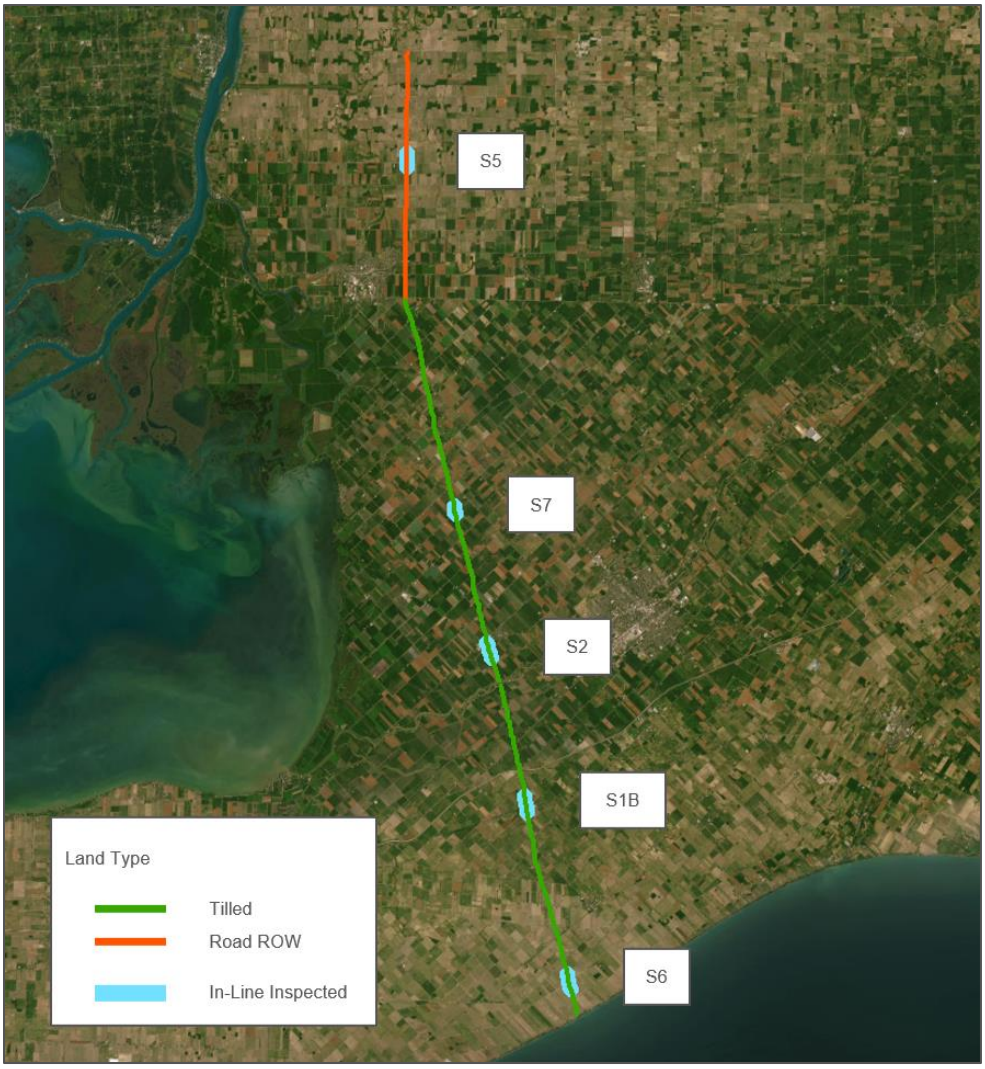


Figure 3.2: NPS 10 Sarnia South Pipeline - Land Type

3.2.1 Third-Party Damage Caused by Farming Equipment

For portions of the NPS 10 Sarnia South pipeline that traverse the tilled land of farm fields, farming equipment may cause TPD to the pipeline during agricultural activities. The failure rate due to farming-related TPD was derived based on the Pipeline and Hazardous Materials Safety Administration (PHMSA) safety incident database and is estimated to be 2.28E-05 per km.yr [4] [5].

3.2.2 Third-Party Damage Caused by Excavator

The failure rate due to excavation-related TPD was calculated following an industry accepted framework and is expressed as the product of the expected hit rate from third-party excavation equipment and the probability that a hit results in a LoC.

3.2.2.1 Pipeline Hit Rate

The pipeline hit rate is based on an updated hit rate fault tree developed by C-FER Technologies where the hit rate is calculated as the product of the excavation rate and the probability of mechanical damage given excavation activity [6]. For pipelines located within designated ROWs in Class 1 areas, the average excavation rate is estimated to be 4.31E-03 per km.yr, derived using Enbridge Gas Ontario's damage data. This value was applied to the NPS 10 Sarnia South pipeline. For the probability of mechanical damage given excavation activity, the probability values assigned to its parameters varied depending on whether segments of the line are classified as "Vital", as these areas are subject to additional damage prevention practices. Of the segments within the road ROW, 37% are classified as Vital. More details can be found in Appendix B: TPD Mechanical Damage Hit Rate Model.

3.2.2.2 Probability of Damage, Given a Hit

The probability of damage given an excavator strike was estimated using a structural reliability model that estimates the impact force of the strike and the pipeline's structural resistance to damage. Impact force and pipe resistance were modelled as random variables that account for the uncertainty in pipeline characteristics (e.g., wall thickness, ultimate tensile strength (UTS), Charpy toughness, etc.), as well as the uncertainty in load from the excavator.

Puncture and gouged dent modes of failure were considered in the probability of damage assessment, and a simplifying (but not necessarily conservative) assumption was made that both failure modes are predicted to result in large leak failure, corresponding to the Annex O ULS category. More details on the assessment can be found in Section 4.1.2 in the DIMP Risk Algorithm Document (RAD) [7]. The calculated probabilities of damage for each unique combination of pipe properties are shown in Table 3.7.

Table 3.7: Probability of Damage Based on Pipeline Properties

No.	% of Pipeline	NPS	MOP (psi)	Class Location	WT (mm)	Grade (MPa)	UTS (MPa)	2/3 CVN (J)	Probability of Damage
1	30%	10	200	1	5.56	172	310	10	1.24E-01
2	22%	10	200	1	7.09	207	331	10	8.03E-02

3	21%	10	200	1	5.56	207	331	10	1.21E-01
4	13%	10	200	1	7.09	172	310	10	7.90E-02
5	6%	10	200	1	5.56	172	310	20	8.12E-02
6	3%	10	200	1	5.56	207	331	20	7.71E-02
7	2%	10	200	1	7.09	290	414	10	7.32E-02
8	1%	10	200	1	5.56	290	414	10	1.10E-01
9	1%	10	200	1	5.56	290	414	20	6.85E-02
10	<1%	10	200	1	9.27	290	414	20	2.36E-02
11	<1%	10	200	1	5.56	359	455	20	6.78E-02
12	<1%	10	200	1	7.09	172	310	20	4.80E-02
13	<1%	10	200	1	9.27	172	310	20	2.78E-02
14	<1%	10	200	1	9.27	290	414	10	4.32E-02
15	<1%	10	200	1	7.09	290	414	20	4.38E-02
16	<1%	10	200	1	6.35	172	310	10	9.63E-02

3.2.3 Third-Party Damage Failure Rate

The estimated average TPD failure rates for the tilled portions and portions within the road ROW are 2.28E-05 per km.yr and 7.53E-05 per km.yr, respectively. As a result, the total pipeline is estimated to have an average TPD (large leak) failure rate of 3.61E-05 per km.yr. The corresponding TPD equivalent rupture failure rate is 1.33E-06 per km.yr after converting the large leak rate into an equivalent rupture rate using Equation O.4 in CSA Z662-23 Annex O [2]. The calculated TPD failure rates are summarized in Table 3.8.

Table 3.8: TPD Large Leak and Equivalent Rupture Failure Rates

Pipeline	Length (km)	Large Leak Failure Rate per km.yr	Equivalent Rupture Failure Rate per km.yr
Tilled Portions	45.24	2.28E-05	8.40E-07
Portions Within Road ROW	15.29	7.53E-05	2.77E-06
Total	**60.53**	**3.61E-05**	**1.33E-06**

3.3 Threats of Compression Couplings and Aerial Crossings

Compression couplings and aerial crossings have been observed along the NPS 10 Sarnia South pipeline and are identified as features that may pose risks.

3.3.1 Population

3.3.1.1 Compression Couplings

To estimate the number of compression couplings along the NPS 10 Sarnia South pipeline, ILI results in Table 2.6 of Section 2.2.4 were used and the following assumptions were made:

- Count on inspected portions: Directly from the ILI results
- Count on uninspected portions: Based on the average population density derived using the ILI results
- Type of restraint: Assumed to be primarily unrestrained, as 90% of compression couplings identified by the ILI tool were reported as unrestrained

As a result, it is estimated that approximately 5,536 compression couplings are present along the line where the majority are assumed to be unrestrained.

3.3.1.2 Aerial Crossings

At Enbridge Gas Ontario, an aerial crossing inspection and survey program was initiated in 2021 to better understand the asset scope and condition. All findings from the program are compiled into a master list that summarizes key information including the total population, aerial crossing attributes and conditions, and identified leaks. Based on this dataset, it is estimated that approximately 42 aerial crossings exist along the NPS 10 Sarnia South pipeline.

3.3.2 Risks

Compression couplings and aerial crossings pose potential risks due to the possibility of failure. For compression couplings, failures may include seal leaks and pull-out incidents. As for aerial crossings, failures may include corrosion-related leaks and large leaks or ruptures caused by outside forces. A review of historical incident rates across Enbridge Gas Ontario and PHMSA suggest that the NPS 10 Sarnia South pipeline may be susceptible to such risks due to the large number of these features along the line. A further analysis is required to quantify these risks in greater detail and account for line-specific attributes (e.g., the NPS 10 Sarnia South pipeline is in a rural area).

In the interim, existing procedures and programs are in place at Enbridge Gas Ontario to control these risks, including safe excavation procedures around unrestrained compression couplings and an aerial crossing inspection and survey program [8] [9].

4. Tolerable Reliability Levels

4.1 Reliability Thresholds

The CSA Z662 Annex O standard provides guidance for operators to apply reliability-based thresholds to their pipeline systems for the LLS and ULS categories.

The LLS reliability threshold for natural gas pipelines is recommended to be 1.0E-03 per km.yr based on a combination of leak impact analysis, historical leak rates, and calibration to ASME B31.8 and CSA Z662 [2].

The ULS reliability threshold for natural gas pipelines is developed by considering the risk of natural gas ignited releases on human safety. The consequences of natural gas pipeline failure are proportional to the population density ρ, probability of ignition, and the hazard area; since the probability of ignition is approximately proportional to the diameter D, and hazard area is proportional to PD^2 where P is the pipeline pressure, the reliability thresholds are defined as an increasing function of ρPD^3. For an NPS 10 pipeline at 200 psi MOP in a Class 1 (rural) location, the ULS threshold is recommended to be 1.0E-03 per km.yr [2].

4.2 Segment Reliability

Failure rates for each individual 1 km segment are shown in Figure 4.1 and Figure 4.2 for the LLS and ULS categories, respectively, along with their respective limits and targets. The LLS limit and target have been set by adopting the Annex O LLS threshold as the limit (i.e., red line) and one order of magnitude lower than the limit as the target (i.e., green line). For ULS, the Annex O ULS threshold has been adopted as the limit and the Enbridge ULS threshold (1.0E-05 per km.yr) has been adopted as the target.

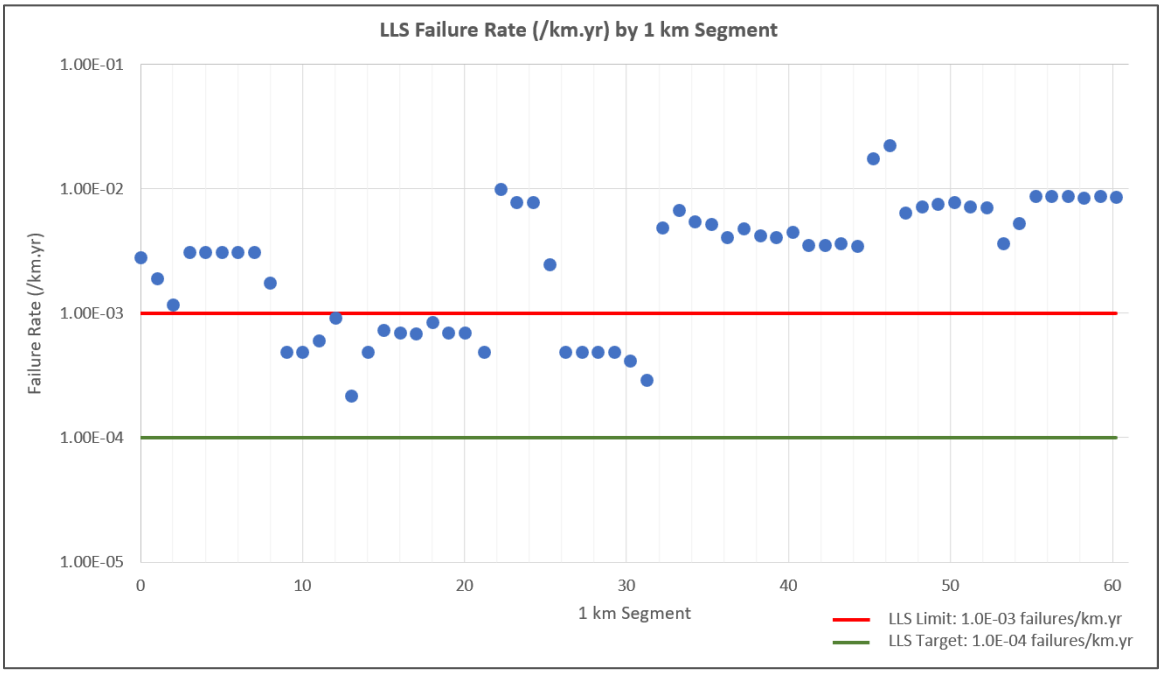


Figure 4.1: NPS 10 Sarnia South Pipeline - Annex O LLS Assessment

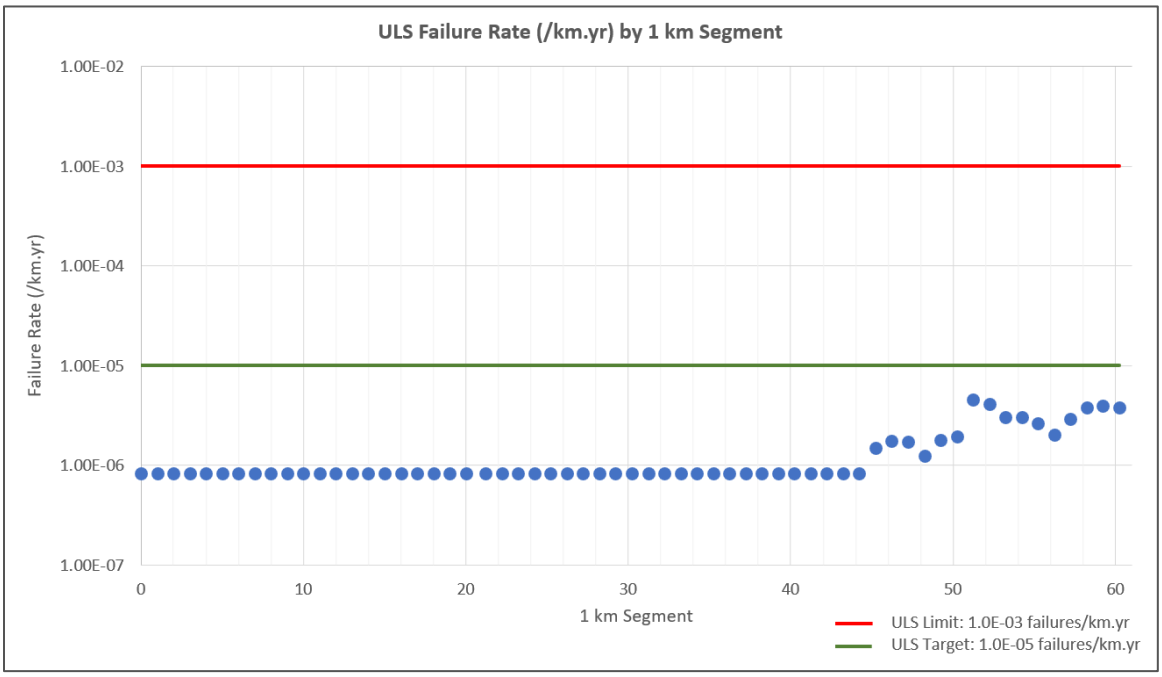


Figure 4.2: NPS 10 Sarnia South Pipeline - Annex O ULS Assessment

4.3 Reliability Maps

Figure 4.3 and Figure 4.4 show the reliability of the pipeline based on the LLS and the ULS, respectively, with 1 km segmentation granularity where the south end is considered the pipeline start (i.e., 0 m). Colouring has been applied based on each limit state's respective limit and target.

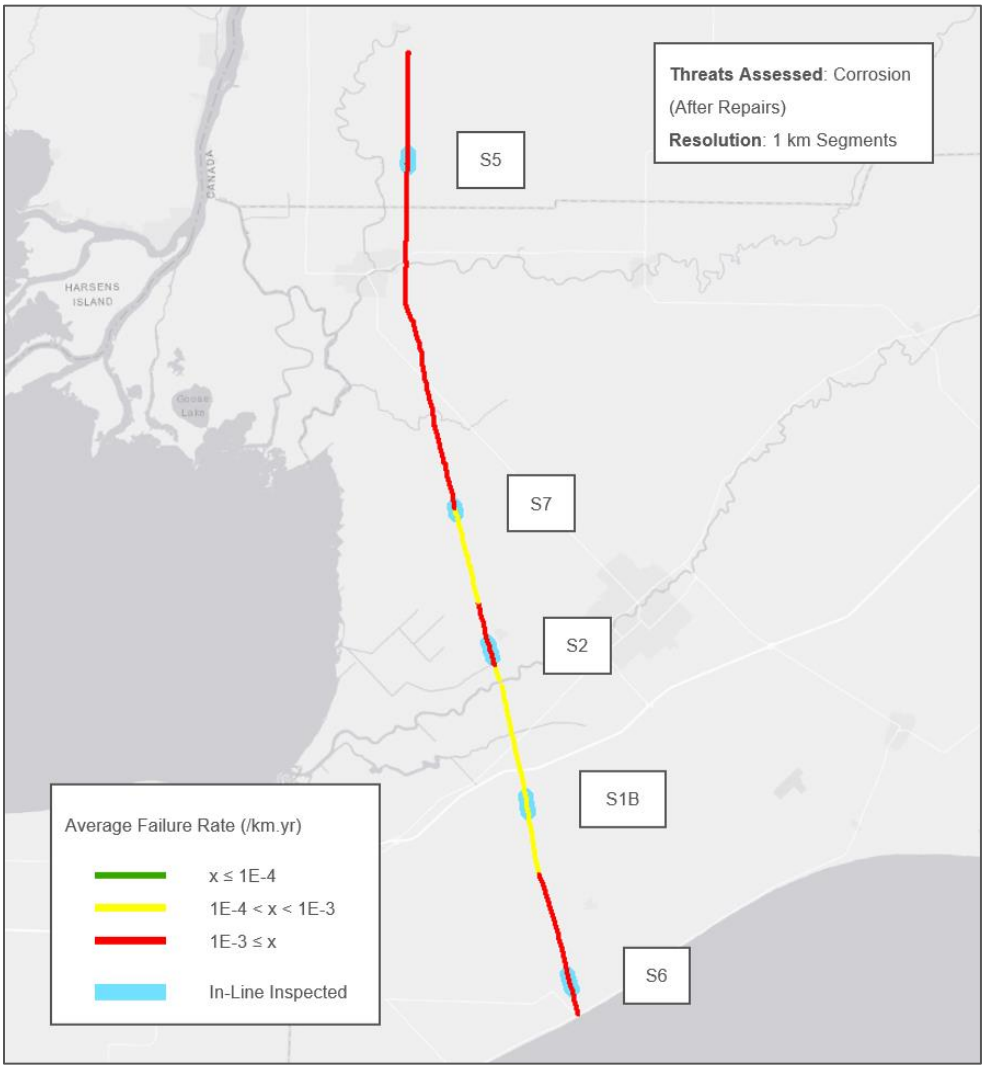


Figure 4.3: NPS 10 Sarnia South Pipeline - LLS Map (1 km Segments)

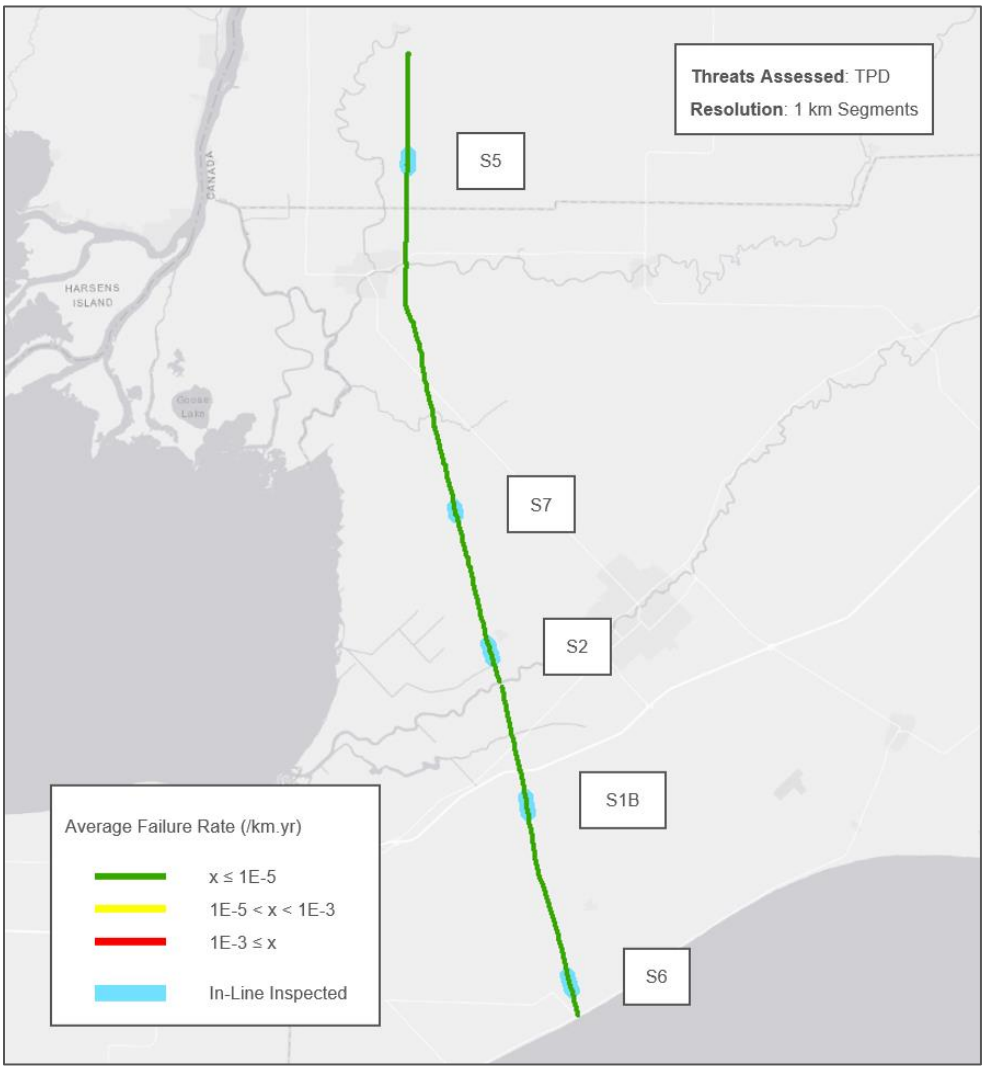


Figure 4.4: NPS 10 Sarnia South Pipeline - ULS Map (1 km Segments)

Figure 4.5 shows the overall reliability of the pipeline by combining the LLS and ULS categories as assessed against their respective limits and targets. The combined reliability map is coloured based on the worst-case reliability level from either the LLS or ULS map (i.e., “Above Limit” means that either the LLS or ULS limit was exceeded).

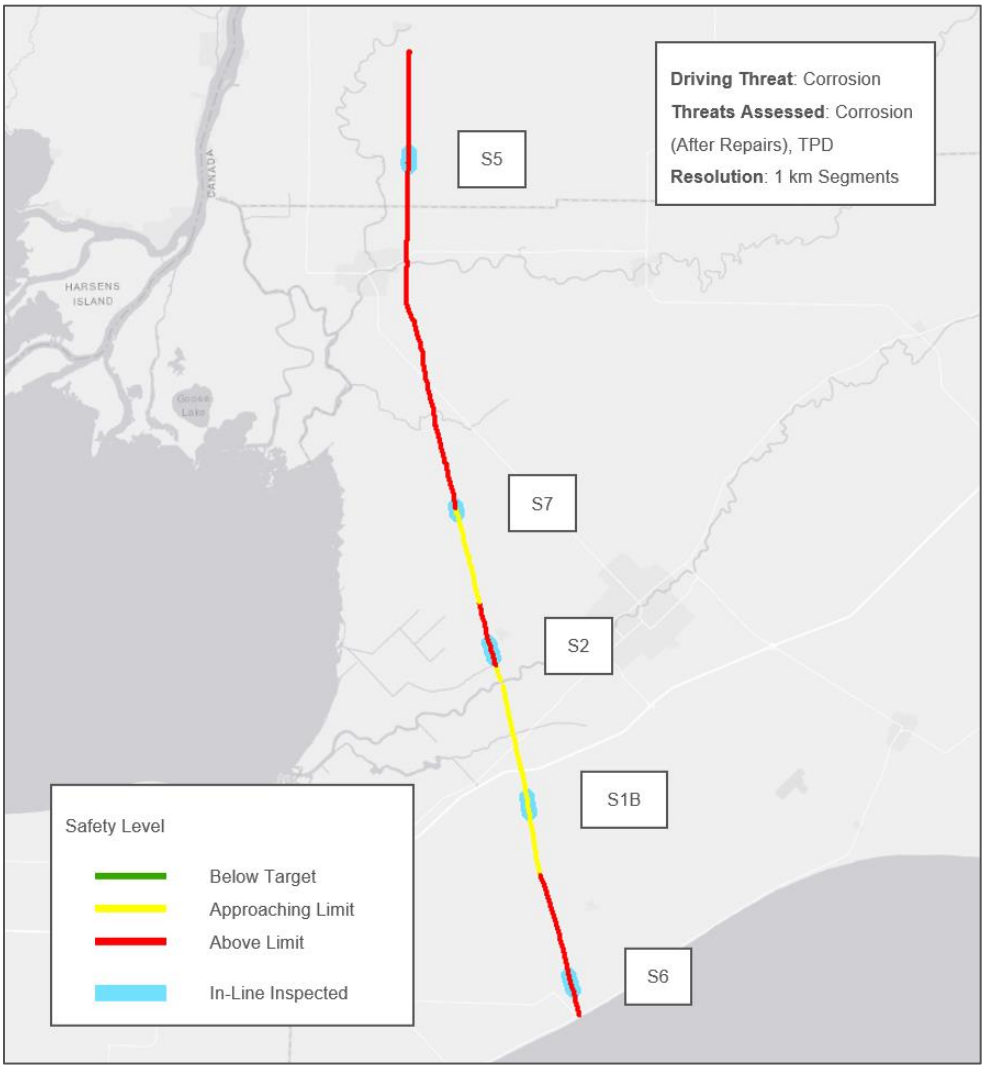


Figure 4.5: NPS 10 Sarnia South Pipeline - Combined LLS and ULS Map (1 km Segments)

Based on Figure 4.5, the safety level of six 1 km segments with partially inspected areas is above the LLS or ULS limit. In each case, corrosion is the driving threat, with the uninspected portions of the segment being the main contributors.

5. Enbridge Operational Risk Assessment Matrix Mapping

The Enbridge Operational Risk Assessment Matrix (see Figure 5.1) was applied to the assessment of scenarios that could result in health and safety impacts to the public, customer disruption, or financial losses. The application of the risk matrix was performed by leveraging the assessed reliability in Section 3 with additional conditional probabilities that a given outcome will occur and potential consequences resulting from the scenario. The consequences were determined by consulting with SMEs and incorporating data-driven models, where available.

As the NPS 10 Sarnia South pipeline is 60.53 km in length, a sliding 10 km window was assessed at 1 km increments along the line and mapped to the risk matrix. The assessment scope of 10 km was chosen based on precedent.

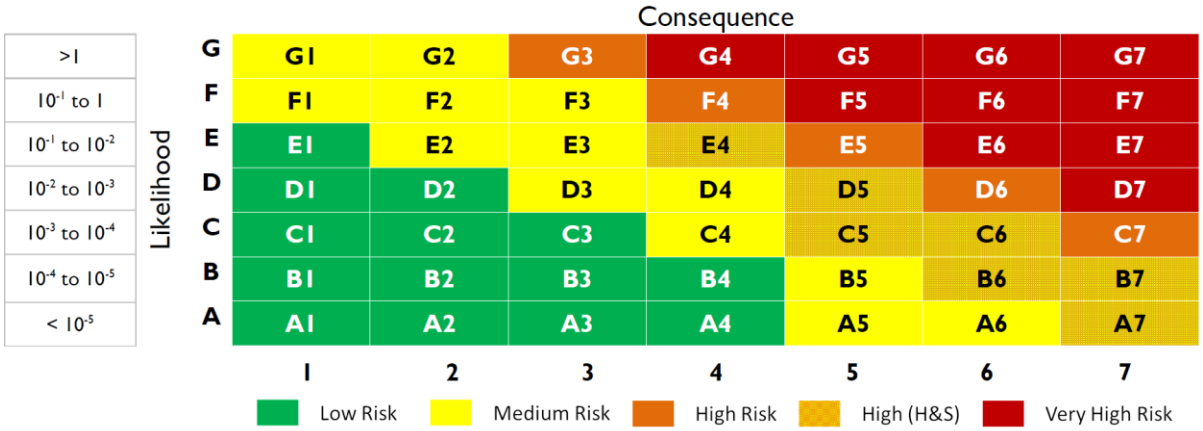


Figure 5.1: Enbridge Operational Risk Assessment Matrix

5.1 Health & Safety Risk

5.1.1 Health & Safety Outcome 1 (HS1) - Migration and Explosion of Nearby Structure

Pipeline leaks may pose a significant health and safety risk if gas migrates into a nearby building and causes an explosion. In this scenario, an underground leak migrates through the soil or via below-ground infrastructure, reaches an enclosed area or structure, accumulates to ignitable gas concentrations, and encounters an ignition source.

Various segments of the NPS 10 Sarnia South pipeline are located near buildings and thus, in the event of a small or large leak, these segments are considered susceptible to gas migration and explosion.

5.1.1.1 HS1 Probability

The probability of a migration and explosion event was determined by calculating the product of the probability of failure, the percentage of pipe segments within a 75 m distance of a building (in which a migration and explosion event is possible), and the conditional probability that the leak migrates into a nearby building and causes an explosion listed in Table 5.1. The conditional probabilities of migration and explosion have been determined through a review of migration-related ignitions in the PHMSA incident repository and represent system-wide averages. The full details of the approach to determine conditional probabilities of migration and explosion are outlined in Section 5.1.1 in the DIMP RAD [7].

On average, approximately 13% of the NPS 10 Sarnia South pipeline is within a 75 m distance of a building as the line traverses a rural landscape primarily used for agriculture. Segments not located near a building contribute zero to the health and safety risk regarding gas migration and explosion.

Table 5.1: Probability of Migration and Explosion Given a Failure

Threat	Probability of Migration and Explosion Given a Failure (Industry Average for Steel Mains)
Corrosion (Small Leak)	1.79E-04
TPD (Large Leak)	4.09E-04

5.1.1.2 HS1 Consequence

The NPS 10 Sarnia South pipeline traverses a rural setting, and based on building footprints sourced from public datasets (OpenStreetMap and Microsoft Bing Maps), there are approximately 126 buildings within 75 m of the pipeline in which a migration and explosion event is possible [10] [11]. The consequences due to health and safety are qualitatively estimated based on its location and Section 5.3.1 in the DIMP RAD, and are shown in Table 5.2 [7].

Table 5.2: Fatality Risks of a Migration and Explosion Event

Estimate	Fatality	Justification
Minimum	0.5	The minimum fatality consequence assumes an explosion in an unoccupied structure, likely only resulting in possible injuries.
Most Likely	1	The best estimate for fatality consequence for a residential or agricultural structure.
Maximum	5	The maximum fatality consequence assumes a failure in a community-use facility or small commercial building (e.g., local business).

5.1.2 Health & Safety Outcome 2 (HS2) - Local Ignition at Failure Site

Large leaks may also pose a significant health and safety risk through immediate or delayed ignition near the source of the failure. In this scenario, ignition may occur immediately if sufficient kinetic energy is present in the initial moment of burst, or after a slight delay until the gas encounters a nearby ignition source (e.g., excavation equipment). Both jet fires and flash fires have been observed in industry on distribution pipelines.

5.1.2.1 HS2 Probability

The probability of a local ignition event was determined by multiplying the probability of failure by the conditional probability that the large leak ignites listed in Table 5.3. The probability of local ignition at the failure site can be estimated by calculating the expected mass flowrate of gas following failure described in Section 5.2 in the DIMP RAD and using the ignition probabilities for a rural release listed in the OGP Report 434-6.1 [7] [12].

Table 5.3: Probability of Local Ignition Given a Failure

Threat	Release Rate (kg/s)	Probability of Local Ignition Given a Failure
Large Leak	3.06	1.69E-03

5.1.2.2 HS2 Consequence

The health and safety consequences of a local ignition event can vary from injuries to fatalities depending on the magnitude of the fire and the number and vulnerability of people present. For the NPS 10 Sarnia South pipeline, these consequences are qualitatively estimated as shown in Table 5.4.

Table 5.4: Fatality Risks of a Local Ignition Event

Estimate	Fatality	Justification
Minimum	0.5	No fatalities and possible injuries.
Most Likely	1	The best estimate for fatality consequence assumes a failure with an exposed individual present (likely during excavation activities).
Maximum	5	The maximum fatality consequence assumes a failure affecting a populated area along the NPS 10 Sarnia South pipeline.

5.1.3 Health & Safety Risk - Operational Risk Assessment Matrix Mapping

The results of the assessed health and safety risk outcomes for the NPS 10 Sarnia South pipeline are shown in Figure 5.2. Each point on the risk matrix corresponds to a 10 km assessment window of the line, evaluated at a 1 km resolution.

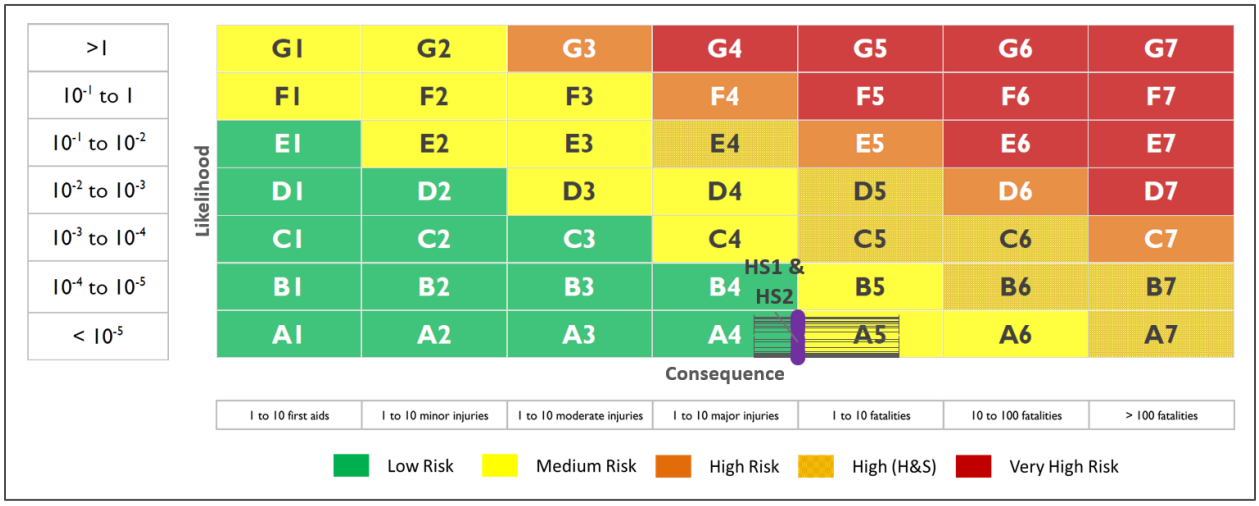


Figure 5.2: Enbridge Operational Risk Assessment Matrix - Health & Safety Risk

5.2 Operational Disruption Risk

5.2.1 Operational Disruption Outcome 1 (OD1) - Customer Losses Due to Operational Disruptions

In an emergency where a leak on a pipeline is confirmed, Enbridge's top priority is to perform "Make Safe" actions to protect its workers and the public from harm. Enbridge will also consider any possible environmental impacts of a large leak to ensure it meets its Environmental, Social, and Governance (ESG) commitments. Based on a case-by-case assessment, it may be required to perform an immediate isolation of the hazardous pipe segment by closing nearby valves or restricting the gas flow using a "squeeze-off" technique, resulting in potential customer loss.

5.2.1.1 OD1 Probability

The probability of an operational disruption event was determined by multiplying the probability of failure by the conditional probability that the failure would lead to an operational disruption shown in Table 5.5. Conditional probabilities were based on SME judgement and industry data.

Table 5.5: Probability of Operational Disruption Given a Failure

Threat	Probability of Operational Disruption Given a Failure
Small Leak	0.01
Large Leak	0.80

5.2.1.2 OD1 Consequence

Customers that are reliant on the NPS 10 Sarnia South pipeline system include those in residential buildings and agricultural facilities, who count on a reliable, dependable energy source for their daily operations. A review of gas demand has been completed to assess the customer impact of a service shutdown (i.e., isolation using mainline valves) for a range of scenarios including 0-degree day (summer), fall peak, and design day (winter). A qualitative assessment of the operational disruption consequences was completed by comparing the simulated customer loss scenarios with the business-unit specific operational disruption consequence criteria as shown in Table 5.6.

In addition, the location at which the failure occurs along the pipeline can impact the number of customer losses, resulting in a large range of possible outcomes. For example, in the event of a service shutdown for a design day scenario, the first 15.5 km of the line (south portion) is estimated to lose over 3,000 customers whereas the rest of the line is estimated to lose under 1,000 customers.

Table 5.6: Operational Disruption Customer Loss

Estimate	Customer Loss Consequence Category	Justification
Minimum	1 - 4	Isolation in the event of an emergency for a 0-degree day (summer) scenario.
Most Likely	2 - 5	Isolation in the event of an emergency for a design day (winter) scenario as it represents typical conditions.
Maximum	2 - 6	Isolation in the event of an emergency for a fall peak scenario as there is less capacity due to the grain dryers that run between September and November.

5.2.2 Operational Disruption Risk - Operational Risk Assessment Matrix Mapping

The results of the assessed operational disruption risk outcomes for the NPS 10 Sarnia South pipeline are shown in Figure 5.3. Each point on the risk matrix corresponds to a 10 km assessment window of the line, evaluated at a 1 km resolution.

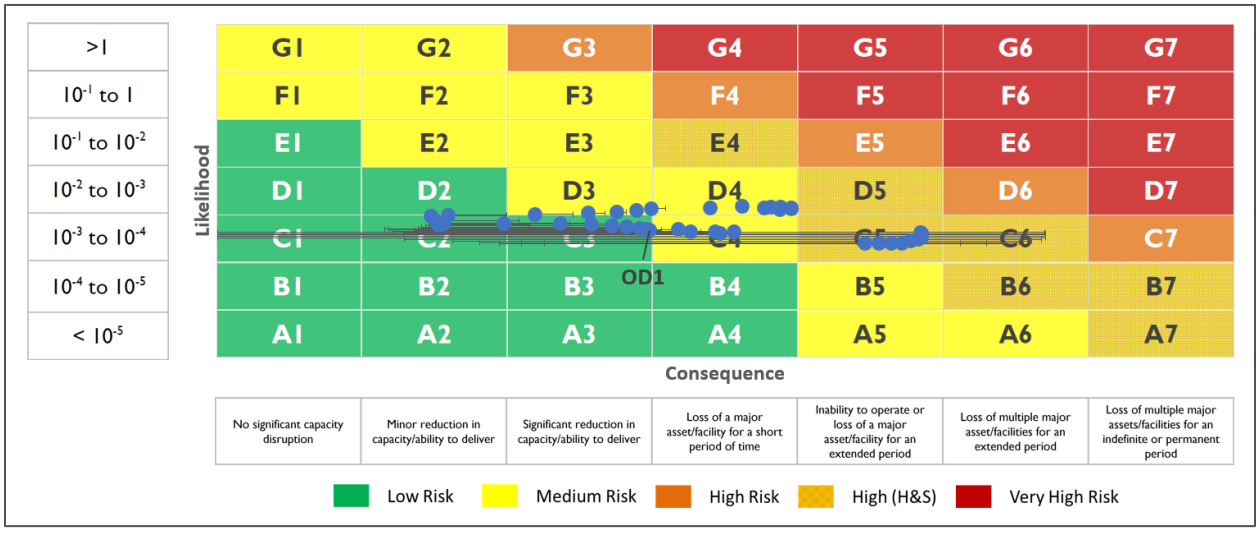


Figure 5.3: Enbridge Operational Risk Assessment Matrix - Operational Disruption Risk

5.3 Financial Risk

5.3.1 Financial Outcome 1 (F1) - Small Leak Resulting in Pipeline Repair or Replacement

The highest financial risk is associated with the scenario of a small leak on the NPS 10 Sarnia South pipeline where an immediate repair of the pipeline is necessary and will result in repair costs including planning, permitting, excavation, and materials. Given the immediate need for the repair, the emergency nature of the work will increase the costs in comparison to the same work completed on a planned basis due to expedited planning and permitting requirements and overtime work. In addition, timing of the repair cannot be planned to minimize gas demands, resulting in the possibility of performing a repair at a time of the year with high gas demands which requires installation of larger bypass piping (if bypass is possible) to mitigate any customer impacts.

5.3.1.1 F1 Probability

The probability of a pipeline repair is the product of the small leak failure rate and the total length of pipe segments.

5.3.1.2 F1 Consequence

The costs associated with an emergency repair of a small leak on the NPS 10 Sarnia South pipeline were determined through consultation with Operations and Engineering Construction. It was assumed that the most likely repair type would be a pipe cut-out and replacement. Given that the costs of a leak can vary, the consequences are presented as a range of values shown in Table 5.7.

Table 5.7: Pipeline Repair Costs of Corrosion Leak

Estimate	Value ($)	Justification
Minimum	$250,000	The total cost of a pipe cut-out and replacement can vary based on the length of the cut-out, geographical location, landowner engagement, and suitable metal landing spots for tie-in.
Most Likely	$1,000,000	
Maximum	$2,000,000	

5.3.2 Financial Risk - Operational Risk Assessment Matrix Mapping

The results of the assessed financial risk outcomes for the NPS 10 Sarnia South pipeline are shown in Figure 5.4. Each point on the risk matrix corresponds to a 10 km assessment window of the line, evaluated at a 1 km resolution.

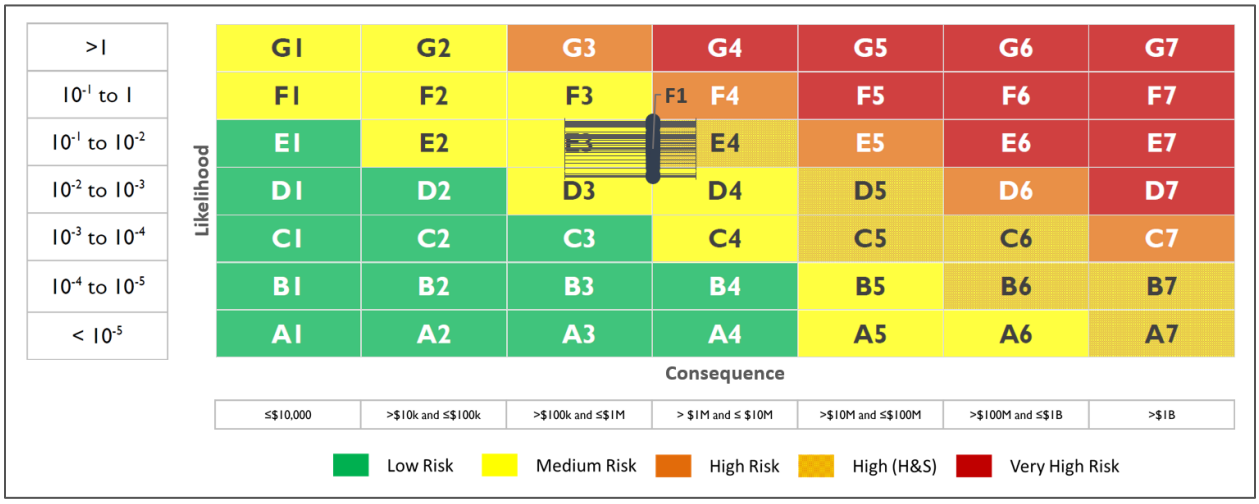


Figure 5.4: Enbridge Operational Risk Assessment Matrix - Financial Risk

5.4 Combined Operational Risk Assessment Matrix Plot

The most significant risks associated with a failure of the NPS 10 Sarnia South pipeline are overlayed in Figure 5.5. This mapping uses a combination of quantitative inputs and qualitative assessments to assess the risk based on the Enbridge Operational Risk Assessment Matrix. As such, various possible outcomes on the NPS 10 Sarnia South pipeline meet the enterprise Safety & Reliability Framework definition of “Medium Risk”.

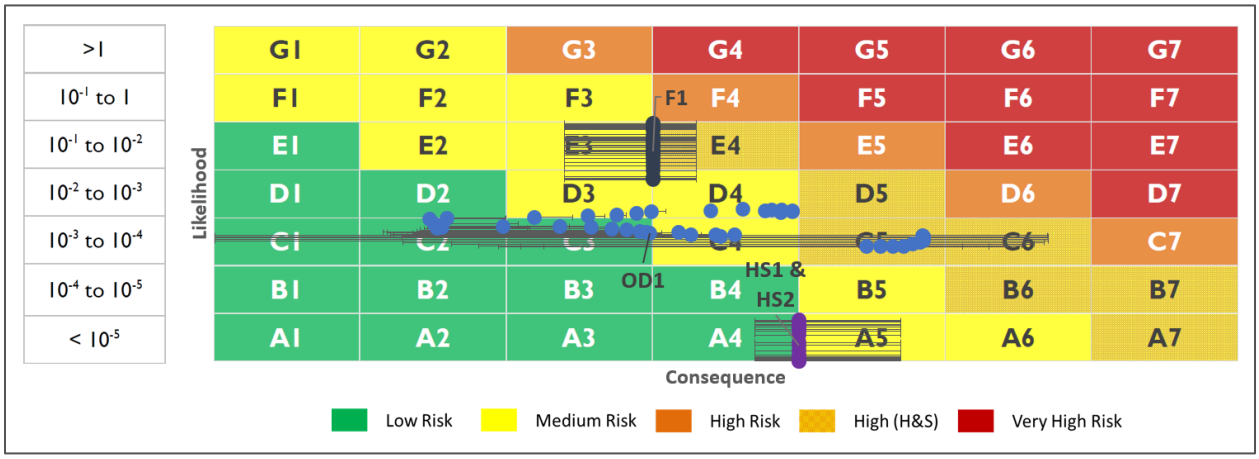


Figure 5.5: Enbridge Operational Risk Assessment Matrix - All Significant Outcomes

6. Recommendations

A risk assessment utilizing a defense-in-depth approach was conducted to evaluate the reliability and risk of the NPS 10 Sarnia South pipeline considering corrosion and TPD threats to its pipeline integrity.

Failure rates were calculated based on historical information and best practice reliability models and then compared to industry benchmarks. The assessment supports the following conclusions:

- 41.62 km of the 60.53 km pipeline (69%) is assessed to have a small leak failure rate above the 1.0E-03 per km.yr LLS limit described by CSA Z662 Annex O.
- 0 km of the 60.53 km pipeline (0%) is assessed to have a large leak (or equivalent rupture) failure rate above the 1.0E-03 per km.yr ULS limit described by CSA Z662 Annex O for an NPS 10 pipeline at 200 psi MOP in a Class 1 (rural) location.
- Integrating the LLS and ULS approaches, 41.62 km of the 60.53 km pipeline (69%) fails one or both reliability limits.

To take into account the overall risks of a failure on the pipeline system, the quantitative reliability assessment was supplemented with consequences of various outcomes and mapped to the Enbridge Operational Risk Assessment Matrix. This exercise concluded that various risk scenarios meet the Enbridge Operational Risk Assessment Matrix definition of “Medium Risk”.

In conclusion, although the NPS 10 Sarnia South pipeline does not meet the LLS thresholds of CSA Z662 Annex O, the line currently does not exhibit high safety, operational, or financial risks with respect to corrosion and TPD. However, the presence of compression couplings and aerial crossings along the line pose potential risks, warranting detailed studies to evaluate these threats and incorporate them into the QRA. It is therefore recommended that additional analysis be performed on these features to assess their risks. In the interim while these risks are being assessed, there are existing procedures and programs at Enbridge Gas Ontario that address these threats, including safe excavation procedures around unrestrained compression couplings, as well as an aerial crossing inspection and survey program.

References

[1] Enbridge Gas Inc., "Quantitative Risk Assessment (QRA) - St. Laurent North Pipeline (EB-2024-0200, Exhibit B, Tab 1, Schedule 1, Attachment 2)," Ontario Energy Board, 2024.

[2] Canadian Standard Association, "CSA Z662:23 Oil and Gas Pipeline Systems - Annex O Reliability-based design and assessment (RBDA) of onshore non-sour service natural gas transmission and LVP liquid hydrocarbon pipelines (CSA Z662:23)," CSA Group, 2023.

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[6] C-FER Technologies, "Next Generation Third-party Mechanical Damage Hit Rate Model," Edmonton, 2023.

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[12] International Association of Oil & Gas Producers, "OGP Risk Assessment Data Directory - Ignition Probabilities (Report No. 434 – 6.1)," 2010.

Appendix A: Pipeline Characteristics Maps

Wall Thickness

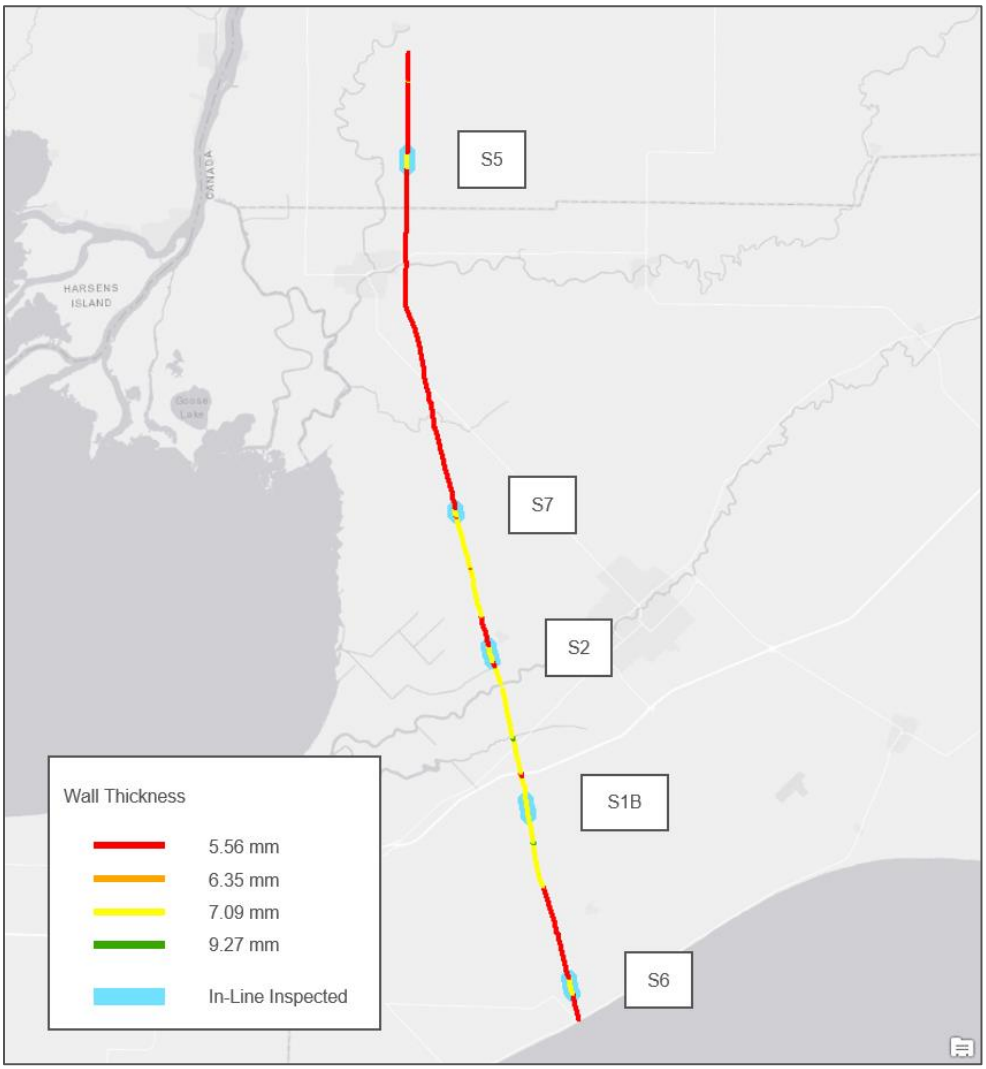


Figure A.1: NPS 10 Sarnia South Pipeline - Wall Thickness[1]

[1] If wall thickness is unknown, 5.56 mm is depicted.

Grade

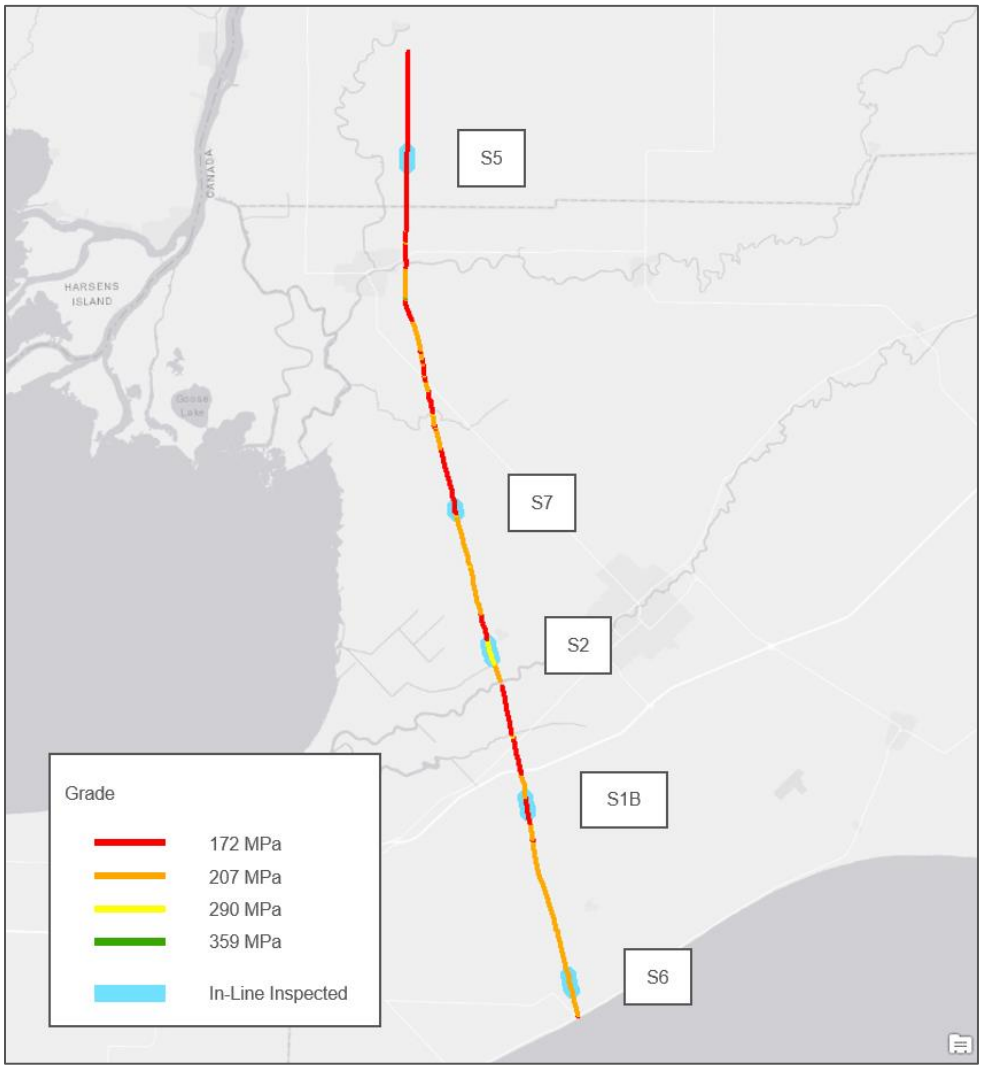


Figure A.2: NPS 10 Sarnia South Pipeline - Grade

ENBRIDGE

Coating

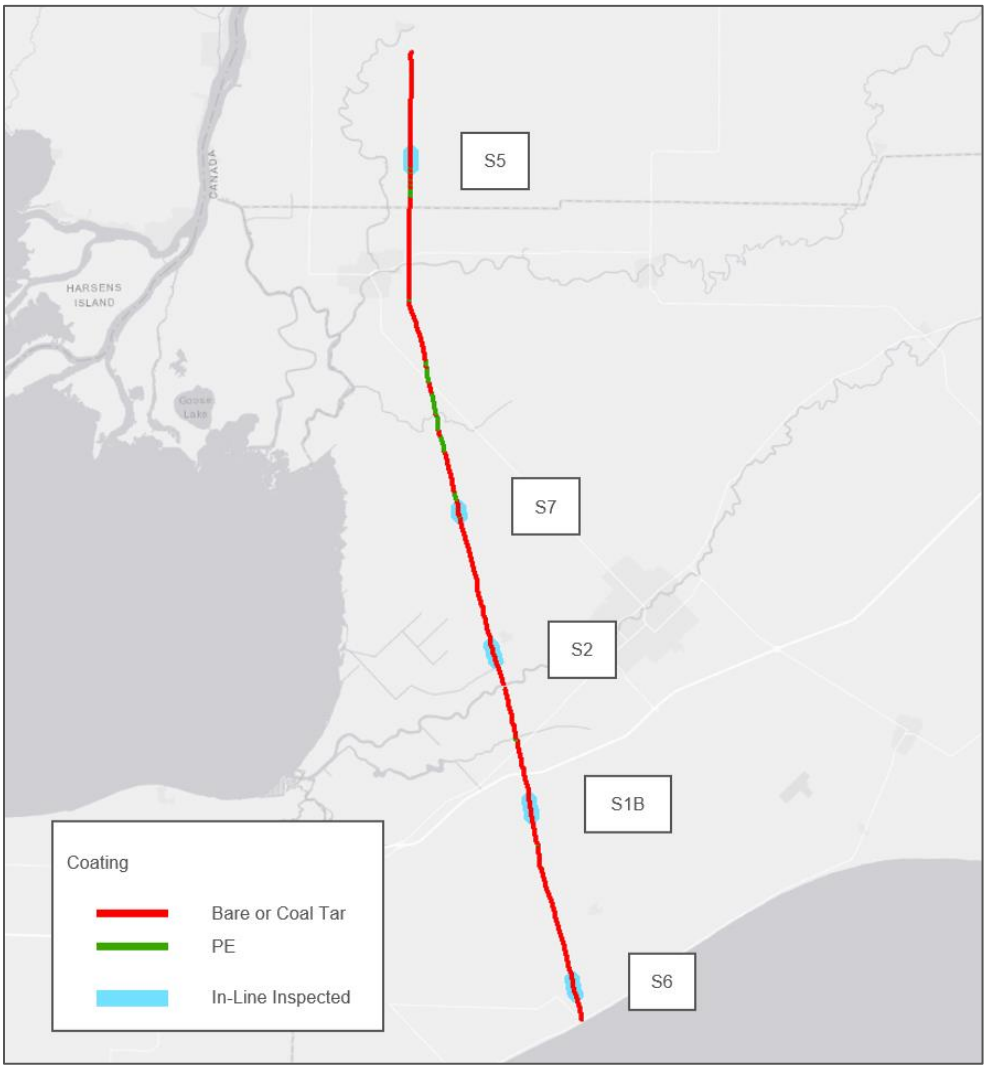


Figure A.3: NPS 10 Sarnia South Pipeline - Coating

Install Year

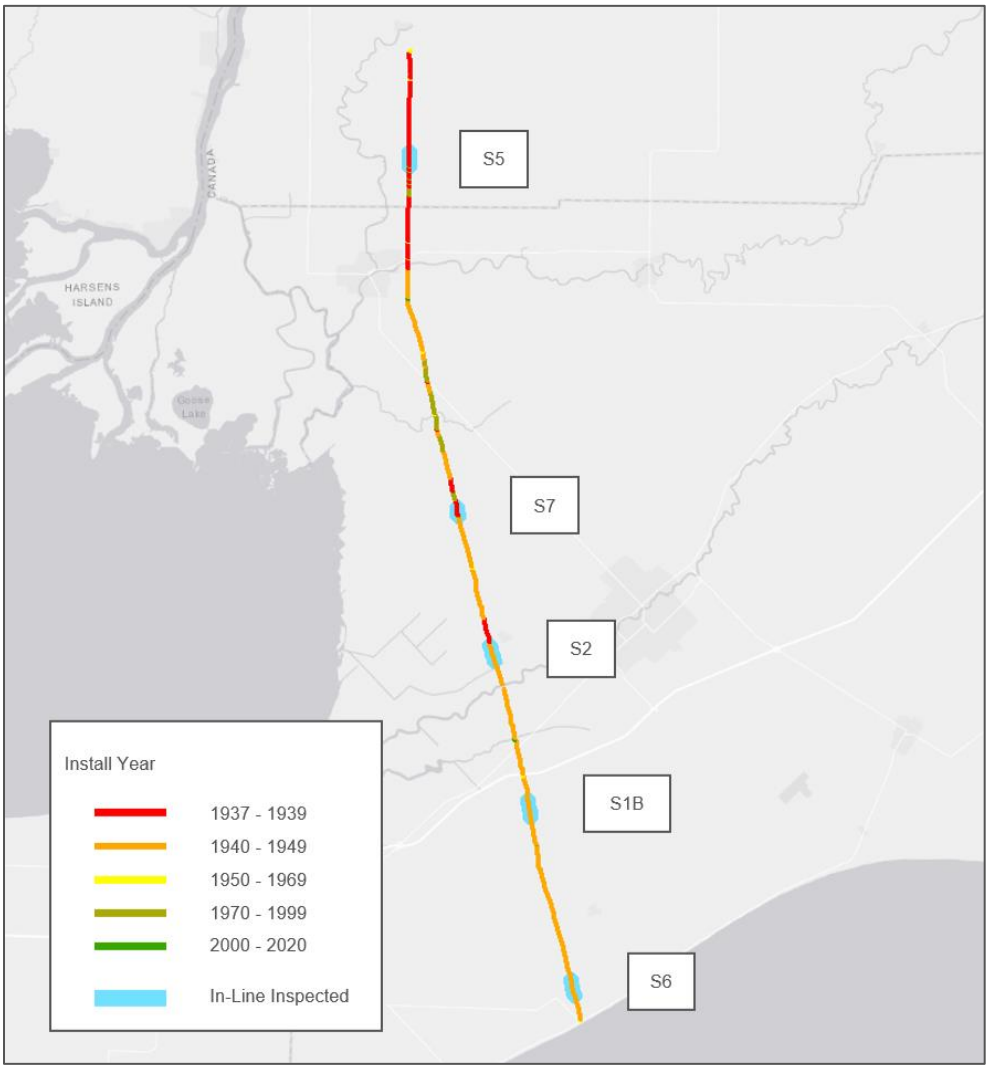


Figure A.4: NPS 10 Sarnia South Pipeline - Install Year

Corrosion Area

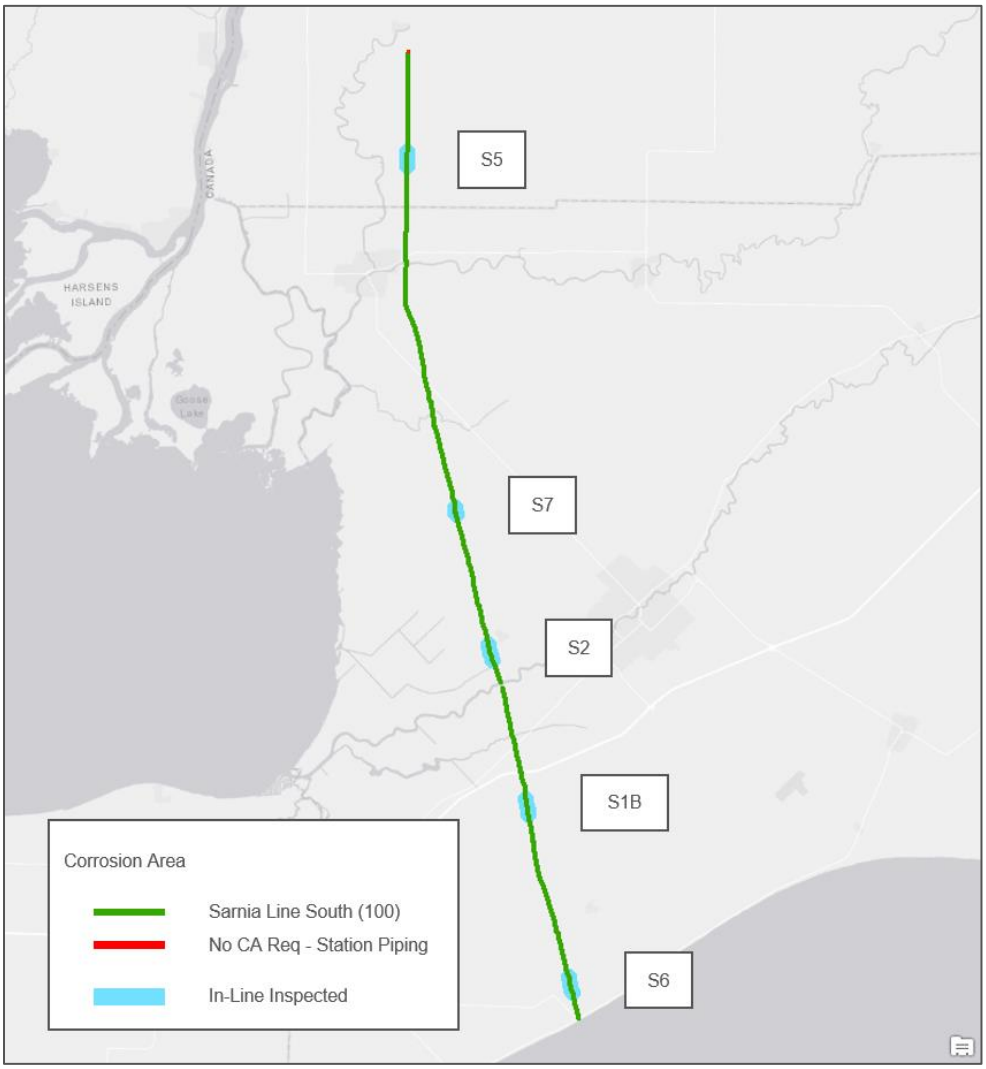


Figure A.5: NPS 10 Sarnia South Pipeline - Corrosion Area

Appendix B: TPD Mechanical Damage Hit Rate Model

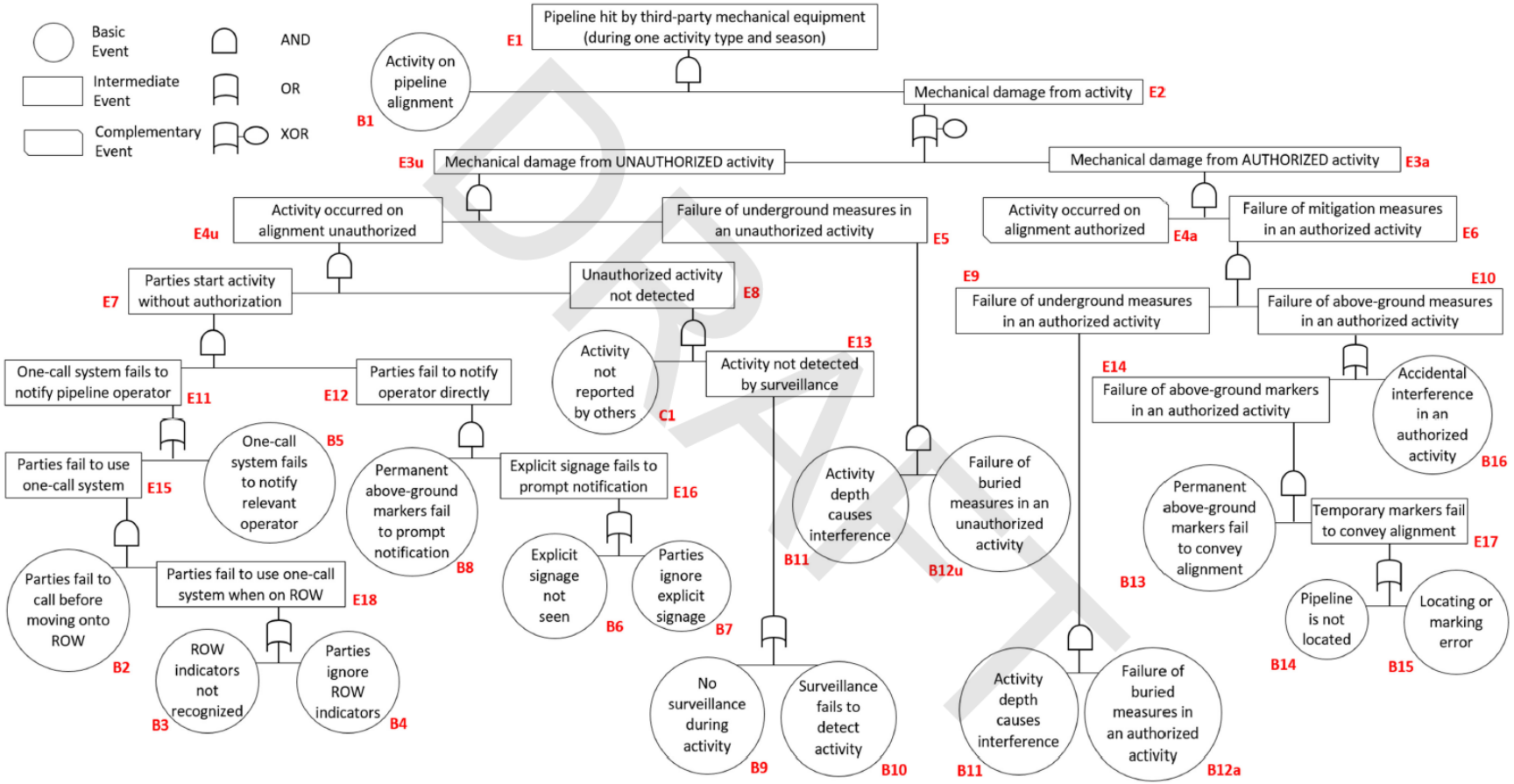


Figure B.1: C-FER TPD Mechanical Damage Hit Rate Model - Fault Tree [6]

Table B.1: Probability Values for Fault Tree Modelling [6]

Factor	Event	Conditions	Probability
B1	Activity on pipeline alignment	Location-specific, derived using Enbridge Gas Ontario's damage data	
B2	Parties fail to call before moving onto ROW	One-call system exists, dig notification required and enforced, average public engagement level, pipeline hazard perception level is low	0.5
B3	ROW indicators not recognized	Continuous but limited ROW indication, average public engagement level, pipeline hazard perception level is low	0.5
B4	Parties ignore ROW indicators	One-call system exists, average public engagement level, pipeline hazard perception level is low	0.35
B5	One-call system fails to notify relevant operator	Unified one-call system to minimum standards	0.005
B6	Explicit signage not seen	No explicit pipeline signage	1.0
B7	Parties ignore explicit signage	Dig notification required and enforced, pipeline hazard perception level is low	0.1
B8	Permanent above-ground markers fail to prompt notification	No permanent above-ground alignment markers	1.0
B9	No surveillance during activity period	Vital: Surveillance interval is weekly Non-Vital: Surveillance interval is annually or longer	0.83 1.0
B10	Surveillance fails to detect activity	Surveillance method is aerial patrol	0.01
B11	Activity depth causes interference	Depth of cover less than 4 metres	$1.13e^{-0.985\times DoC}$
B12a	Failure of buried measures in an authorized activity	No marker tape, no mechanical protection	1.0
B12u	Failure of buried measures in an unauthorized activity	No marker tape, no mechanical protection	1.0
B13	Permanent above-ground markers fail to convey location	No permanent above-ground alignment markers	1.0

B14	Pipeline is not located	Dig notification response time is more than three days	0.037
B15	Locating or marking error	Locating method used is magnetic techniques	0.042
B16	Accidental interference in an authorized activity	Vital: Site supervision provided throughout the activity Non-Vital: Site supervision not available	0.088 0.352
C1	Unauthorized activity not reported by others	Assumed to be a constant value	0.97

NPS 8 Port Stanley and St Thomas Pipelines - Quantitative Risk Assessment (QRA)

November 18, 2025

ENBRIDGE

Integrity Assessments & Risk
Integrity Department

Document Governance

Revision History

Date	Version	Comment	Prepared By	Approved By
2025-11-3	1.0	Initial version	Ziming He Engineer in Training II EDIMP Risk, Integrity Assessment & Risk, Pipelines & Storage	Kai Ji, P.Eng. Supervisor, Integrity Assessment & Risk, Pipelines & Storage
2025-11-18	2.0	Update TPD reliability Update Health & Safety Update Operational Risk	Ziming He Engineer in Training II EDIMP Risk, Integrity Assessment & Risk, Pipelines & Storage	Kai Ji, P.Eng. Supervisor, Integrity Assessment & Risk, Pipelines & Storage

1. Introduction

The NPS 8 Port Stanley and NPS 8 St Thomas pipelines were identified as 2024 EDIMP priority pipelines and in-line inspections (ILIs) were performed in 2024 to assess the condition of the lines.

Subsequently, a Quantitative Risk Assessment (QRA) has been conducted to assess the risk of the NPS 8 Port Stanley and NPS 8 St Thomas pipelines. Methodologies used in the QRA are similar to those used in the St. Laurent Pipeline (SLP) Replacement Project [1]. This report summarizes the QRA performed, and the results will be utilized to develop long-term risk mitigation plans for the NPS 8 Port Stanley and NPS 8 St Thomas pipelines.

2. Background Information

2.1 Pipe Properties

The pipeline characteristics that comprise the majority of the NPS 8 Port Stanley and NPS 8 St Thomas pipelines are shown in Tables 2.1 and 2.2. A detailed breakdown of the complete pipeline characteristics can be found in Appendix A: Pipeline Characteristics Maps.

Table 2.1: Primary Pipeline Specifications of NPS 8 Port Stanley Pipeline

Attribute	Specification	Assumptions
NPS	8 (Majority – 99.8%), 6 (Majority – 0.2%),	
Length	16.21 km	
Install Year	1947 (Majority – 53.1%), 1970 – 1983 (Minority – 2.4%), 2000 – 2005 (44.6%)	
MOP	275 psi	
Wall Thickness	4.78 mm 7 mm	Assumed based on historic light wall pipe within the EGI system[1]
Grade	172 MPa (Majority – 53.1%)	Assumed based on CSA Z662-19 (clause 5.6.4) for pipe with unknown origins
Coating	Coal Tar Enamel	Assumed based on 2024 integrity digs.
% SMYS	23.5%	Based on assumed values.

1.Field NDEs on exposed joints show the nominal pipe wall thickness is 7mm. However, it is not enough to apply to the entire pipeline.

Table 2.2: Primary Pipeline Specifications of NPS 8 St Thomas Pipeline

Attribute	Specification	Assumptions
NPS	8	
Length	4.41 km	

Install Year	1959	
MOP	275 psi	
Wall Thickness	4.78 mm	
Grade	290 MPa	Assumed based on API 5L X42
Coating	Coal Tar Enamel	Assumed based on pipe vintage
% SMYS	15.0%	Based on assumed values.

2.2 Inspection

2.2.1 Coverage

ILI runs across two launch sites were completed at various locations along the NPS 8 Port Stanley pipeline using the Intero Pipe Explorer MFL-LDS robotic crawler inspection tool between July 19th, 2024 and September 26th, 2024. The ILIs captured condition data on 0.59 km (3.7%) of the pipeline. On the other hand, one ILI run along the NPS 8 St Thomas pipeline using the same inspection tool was performed on 0.83 km (18.9%) pipeline on July 16th, 2024. The inspection extents and locations corresponding to NPS 8 Port Stanley and NPS 8 St Thomas pipelines are shown in Figure 2.1.

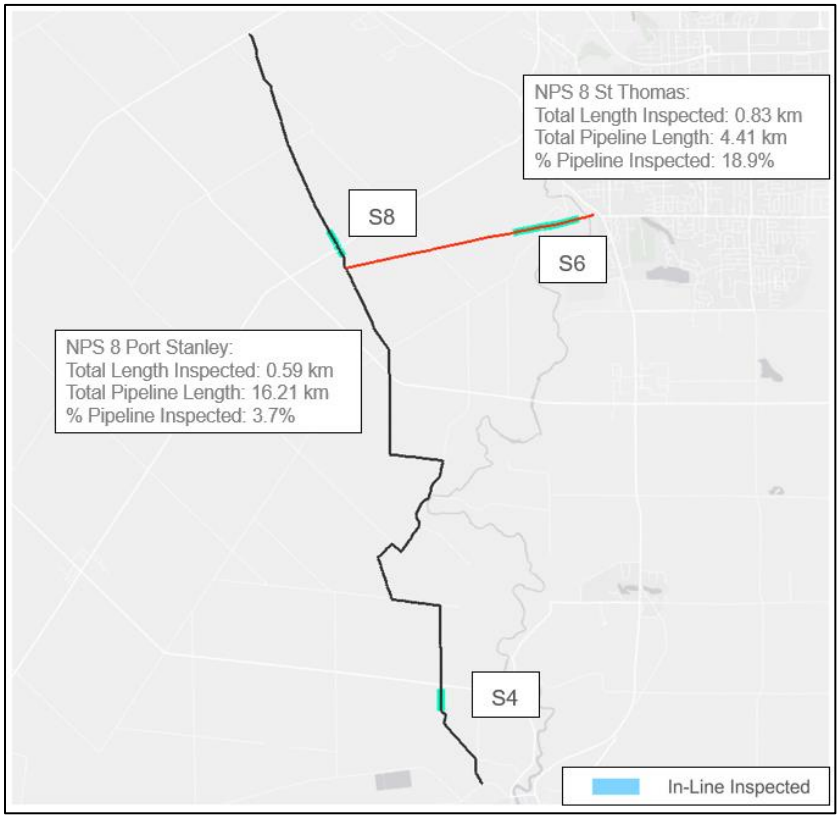


Figure 2.1: Crawler Inspection Extents and Locations on NPS 8 Port Stanley and NPS 8 St Thomas Pipelines

2.2.2 Metal Loss Results (MFL Technology)

A total of 1057 metal loss features above the reporting threshold were reported along the inspected portions of the two pipelines, including 1054 (99.7%) on NPS 8 Port Stanley and 3 (0.3%) on NPS 8 St Thomas, respectively. 2 individual anomalies were identified with metal loss greater or equal to 70% wall loss (Phase 1) on NPS 8 Port Stanley and the majority of anomalies were located as part of inspection S8, while anomalies on NPS 8 St Thomas were below 17% corrosion depth. The number of reported metal loss features by inspection and the resulting feature densities are shown in Table 2.3. As shown in the Table 2.3, metal loss counts were dominated by features found on S8 which exhibited markedly higher corrosion density than the other inspections.

Table 2.3: Reported Metal Loss Features by Inspection

Pipeline	Inspection	Length Inspected (km)	Metal Loss Count	Features / km
NPS 8 Port Stanley	S4	0.168	111	659.3
	S8	0.426	943	2213.8
NPS 8 St Thomas	S6	0.830	3	3.6
Total		**1.424**	**1057**	**742.1**

A histogram showing the count of corrosion depths reported by inspection is shown in Figure 2.2 and all of the most severe features were found on S8.

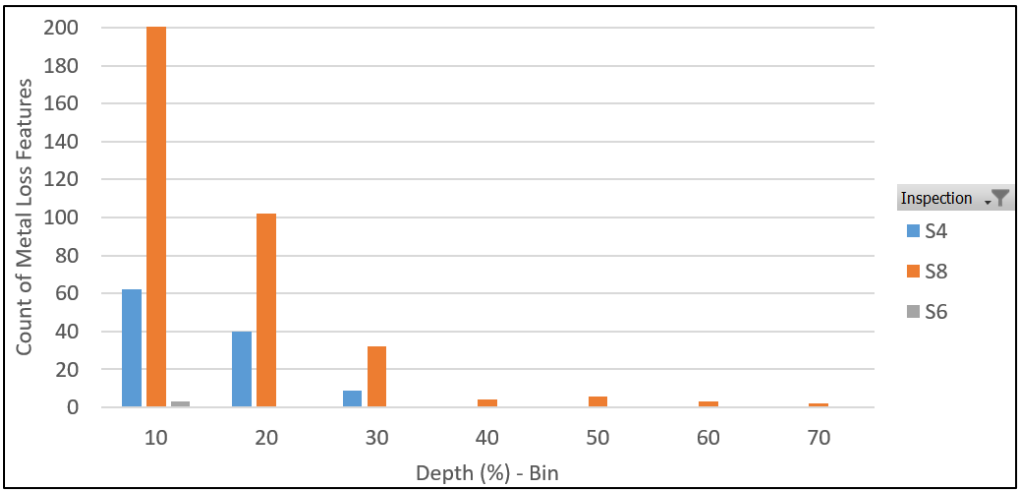


Figure 2.2: Histogram of Metal Loss Depths

2.2.3 Deformation Results (LDS Technology)

2 plain dent features above the reporting threshold were reported along the inspected portions of the pipeline as shown in Table 2.4. It is noted that two dents were reported as top-side (above the 4 and 8 o'clock positions) associated with depths smaller than 2% of the pipeline outer diameter.

Table 2.4: Reported Dents by Inspection

Pipeline	Inspection	Length Inspected (km)	Dent Count	Dents / km
NPS 8 Port Stanley	S4	0.168	0	0
	S8	0.426	1	2.35
NPS 8 St Thomas	S6	0.830	1	1.20
Total		**1.424**	**2**	**1.40**

3. Reliability

The reliability of the NPS 8 Port Stanley and NPS 8 St Thomas pipelines was quantitively assessed by evaluating the susceptibility of the pipeline to corrosion and third-party damage (TPD) threats with potential to cause a loss of containment (LoC) failure. It is noted that although compression coupling and aerial crossing in addition to corrosion and TPD were observed on the pipelines, their reliability outcomes were not included in the current assessment (see Section 3.3). Programs on quantifying compression coupling and aerial crossing failure rates will be initiated in the future.

There are multiple modes which a LoC can occur and are categorized by three release sizes:

- Small Leak
- Large Leak
- Rupture

CSA Z662 Annex O further categorizes the modes into two distinct Limit State categories:

- Leakage Limit State (LLS)
- Ultimate Limit State (ULS)

Definitions can be found in Section 3.1 in the SLP QRA [1].

3.1 Corrosion Threat

3.1.1 Reliability Based on Historical Leaks

Sources containing historical leaks on NPS 8 Port Stanley and NPS 8 St Thomas pipelines were obtained from various stakeholders including Asset Intelligence, DIMP, Leak Survey, Operation and Region and were carefully assessed. The leak counts from different stakeholders were summarized in Table 3.1 and the results could not indicate a good prediction of the failure rate on these lines because the leak counts differ significantly while sources are considered equally trustworthy; in this case, it is unable to determine which record should be considered accurate. Furthermore,

some of the leaks might occur on service lines or fittings instead of mains but this information is not always clearly presented in the sources.

Table 3.1: Leak History on NPS 8 Port Stanley and NPS 8 St Thomas Pipelines from Stakeholders

Team	Source	NPS 8 Port Stanley	NPS 8 St Thomas	Duration
Asset Intelligence	Failure dataset	1	2	2016 - 2024
Asset Intelligence	Work Order	1	7	2001 - 2025
DIMP	FCP	0	0	2016 - 2024
Leak Survey	Manual Check	0	2	2024
Operation	Paper Record	92	NA	1959 - 1983
DIMP	Integrity Assessment report in 2024	27	1	2019 – 2021 (PS) 2013 (St Thomas)
Region	Hetek (External Vendor)	2	NA	2018 - 2019

The paper record summarizing all leaks on NPS 8 Port Stanley pipeline between the period of 1960 and 1970 (see Appendix B) obtained from the Operation team might have the indication of the leak rate. However, this record has some limitations in calculating the leak rate. Firstly, the coatings were recorded as “Bare” or blank for all leaks but Coal Tar Enamel was observed from four NDEs in the inspected 1947 pipe segments in 2024. This suggests that using old leak records that are not aligned with today’s operation is not applicable. Secondly, the record covered leaks from 1959 to 1983 but the initiation of recording failures was not documented. Furthermore, some pipeline segments have been replaced after 1970 and it is unknown whether some leak counts were on pre-replaced pipelines. Finally, the report included the leak data for around 10 miles only and it was unclear whether the whole line was surveyed and leaks were found in these regions only, or 10 miles were surveyed only.

It was therefore decided that the actual failure rate on NPS 8 Port Stanley and NPS 8 St Thomas pipelines was unavailable because of varied leak counts across seven sources.

3.1.2 Reliability Based on Inspection Data

3.1.2.1 Reliability for Inspected Portions

After the inspections, Enbridge Gas completed two repairs to mitigate Phase 1 anomalies shown in Table 3.2.

Table 3.2: Completed Repairs on NPS 8 Port Stanley

Pipeline	Inspection	Repair	Site Location
NPS 8 Port Stanley	S8	Pressure containment sleeve	42.763932, -81.256007
		Pressure containment sleeve	42.7610981, -81.2542870

A structural reliability model was used to calculate the reliability of the pipeline’s inspected portions based on the reported ILI corrosion features by applying the ASME Modified B31G failure criterion and a Probability of Failure (POF)

approach. As such, the small leak average failure rates along the inspected portions are calculated to be 2.05E-02 and 8.87E-18 per km.yr before the repairs and 2.16E-03 and 8.87E-18 per km.yr after the repairs for NPS 8 Port Stanley and NPS 8 St Thomas, respectively, as shown in Table 3.3.

Table 3.3: Average Failure Rates for Inspected Portions Before and After Repairs

Pipeline	Inspection	Length Inspected (km)	Average Failure Rate per km.yr (Before Repairs)	Average Failure Rate per km.yr (After Repairs)
NPS 8 Port Stanley	S4	0.168	1.39E-09	1.39E-09
	S8	0.426	2.86E-02	3.01E-03
	Total	**0.594**	**2.05E-02**	**2.16E-03**
NPS 8 St Thomas	S6	0.830	8.87E-18	8.87E-18
	Total	**0.830**	**8.87E-18**	**8.87E-18**

3.1.2.2 Reliability for Uninspected Portions

To estimate the condition for the rest of the pipeline, ILI results before repairs from the 1.43 km of inspections were extrapolated to uninspected segments using a like-in-kind approach. The like-in-kind approach involves defining “like” segments of pipeline which are considered to have similar key characteristics that are known to influence corrosion.

The pipe body coating and corrosion area (i.e., areas defining continuous cathodic protection) were commonly considered for like-in-kind assessment but the corrosion areas were unavailable on these two pipelines. This suggested that the factor of pipe body coating was considered for defining the appropriate like-in-kind segments only. The coating category was defined in terms of the installation year, i.e. the Coal Tar Enamel (CTE) was assumed for pre-1970 pipe segments (vintaged), while Polyethylene (PE) was assumed for post-1970 segments (modern). The like-in-kind approach was employed on NPS 8 Port Stanley and NPS 8 St Thomas individually.

For the NPS 8 St Thomas pipeline, condition information from inspected segments was extrapolated to uninspected like segments because 18.9% of total length were partially inspected and identical characteristics such as wall thickness, vintage and outside diameter were observed along the whole line. This indicated that the failure rate per km per year from the inspected segments was reasonable to be extrapolated to uninspected segments. On the other hand, it is noted that while 3.7% of the NPS 8 Port Stanley pipeline length has been inspected, 6.8% and 0.2% of CTE- and PE-coated segments were inspected, respectively. Moreover, NPS 8 Port Stanley pipeline has various combinations of wall thicknesses and vintages from the inspected and uninspected regions between the period of 1947 and 2005 while inspection data was collected for pipe installed in 1947 and 1971 only. This suggested that the PYRAMID structural reliability model was employed for post-1970 uninspected pipe segments due to the unrepresentative inspected data while corrosion growth rate bootstrapping was applied to pre-1970 uninspected segments.

It should be noted that while the pipebook indicates that the nominal wall thickness on NPS 8 Port Stanley uninspected vintaged (installed in 1947) pipe segments to be 4.78 mm, a lack of evidence was presented to rule out the probability of 7mm because 97.7% of inspected length were installed in 1947 and NDE results suggested to be around 7mm. Given the uncertainties and limited info on the original wall thickness, it was therefore assumed that bootstrapping

method was applied to uninspected 1947 pipe segments associated with assumed 4.78 mm wall thickness from the pipebook. Two wall thicknesses (i.e. 4.78 and 7 mm) were employed in the bootstrapping and each thickness accounted for 50% to estimate the weighted average POF on uninspected vintaged 1947 pipe segments, representing the uncertainty in the true wall thickness.

3.1.2.3 Reliability for Full Pipeline

The NPS 8 Port Stanley and NPS 8 St Thomas pipelines are estimated to have small leak average failure rates of 1.16E-01 and 8.87E-18 per km.yr, respectively, based on the PYRAMID model and inspection data extrapolated to the uninspected portions (see Section 3.1.2.2). The calculated average failure rates from the inspected and uninspected portions are summarized in Table 3.4.

Table 3.4: Summarized Corrosion Reliability Results

Pipeline	Pipeline	Length (km)	Average Failure Rate per km.yr (Before Repairs)	Average Failure Rate per km.yr (After Repairs)
NPS 8 Port Stanley	Inspected Portions	0.59	2.05E-02	2.16E-03
	Uninspected Portions	15.62	1.20E-01	1.20E-01
	Total	**16.21**	**1.16E-01**	**1.16E-01**
NPS 8 St Thomas	Inspected Portions	0.83	8.87E-18	8.87E-18
	Uninspected Portions	3.58	8.87E-18	8.87E-18
	Total	**4.41**	**8.87E-18**	**8.87E-18**

3.2 Third-Party Damage Threat

The failure rate due to TPD was calculated following an industry accepted framework but it could be further classified as excavation-related or farming-related failure rate in terms of pipeline locations, i.e. NPS 8 Port Stanley and NPS 8 St Thomas pipelines have crossed multiple land uses such as tilled areas and roads and each 100m segment is therefore classified as susceptible farming damages or excavation damages (i.e. in the road Right-of-Way).

3.2.1 Farming Damage Failure Rate

The calculation of farming damage failure rate was conducted by filtering for the farming damages from the PHMSA database. The total pipeline length from PHMSA was combined with GDS-based proportion of farming land use to estimate the PHMSA-regulated pipeline length on the farming land use in a given time period. The final failure rate was estimated to be 2.28E-05 per km.yr as indicated in the TIMP Risk Algorithm Document (RAD) [2].

3.2.2 Excavation Damage Failure Rate

3.2.2.1 Observed Dents on Inspected Portions

To distinguish likely TPD from non-TPD related dents, a filtering criterion was applied to dents reported by the ILI tool to estimate the number of dents that were likely due to mechanical excavator damage. The filtering criterion applied was:

- Subset of top-side dents which are specifically occurring on the top half of the pipeline (between 8:00 and 4:00 o'clock) where mechanical damage is most likely, AND either one of the following criteria:
    - Dents interacting with Metal Loss, OR
    - Dents > 2% of the pipeline outer diameter

A thorough ILI review indicated that two ILI-called plain dents were smaller than 2% of the pipeline outside diameter and thus no ILI-called dents were susceptible to TPD-related dents. A further analysis indicated that the ILI-inspected regions were on the farming land use, which suggested that farming damages could not be ruled out from the assessment on these segments, i.e. the ILI-inspected portions were associated with farming damage failure rate.

3.2.2.2 Estimated Hit Rate

The C-FER Fault Tree Model was employed to evaluate the TPD hit rate for pipe segments in the road ROW [3]. The TPD hit rate was the product of location-specific excavation rate and the probability of mechanical damage given excavation activity. The location-specific excavation rate for pipelines within designated ROWs in Class 1 areas was derived in terms of the One-Call ticket data and geospatial land use data and calculated to be 4.31E-03 per km.yr, while the probability of mechanical damage given excavation activity was computed based on a number of parameters included in the Fault Tree Model to account for different activities. The details of the C-FER Fault Tree Model associated with assumed parameter values could be found in Appendix C.

3.2.2.3 Probability of Damage, Given a Hit

The probability of damage given an excavator strike was estimated using a structural reliability model that estimates the impact force of the strike and the pipeline's structural resistance to damage. Impact force and pipe resistance were modelled as random variables that account for the uncertainty in pipeline characteristics (e.g., wall thickness, ultimate tensile strength (UTS), Charpy toughness, etc.), as well as the uncertainty in load from the excavator.

Puncture and gouged dent modes of failure were considered in the probability of damage assessment, and a simplifying (but not necessarily conservative) assumption was made that both failure modes are predicted to result in large leak failure, corresponding to the Annex O ULS category. More details on the assessment can be found in Section 4.1.2 in the DIMP Risk Algorithm Document (RAD) [4]. The calculated probabilities of damage based on the unique combination of pipe properties are shown in Table 3.5.

Table 3.5: Probability of Damage Based on Pipeline Properties

Pipeline	Grade (MPa)	NPS	WT (mm)	2/3 CVN (J)	UTS (MPa)	MOP (psi)	Class Location	Probability of Damage
NPS 8 Port Stanley	290	8	4.78	20	414	275	1	0.10831
	172	8	4.78	10	310	275	1	0.18026
	172	8	7	10	310	275	1	0.10219
	290	8	6.35	20	414	275	1	0.06261
	172	8	7.11	10	310	275	1	0.09376
	290	8	8.18	20	414	275	1	0.03649
	241	6	7.11	20	414	275	1	0.06713
NPS 8 St Thomas	290	8	4.78	10	414	275	1	0.16182

It is noted that two wall thicknesses were employed on uninspected vintaged 1947 pipe segments in the corrosion assessment and each accounted for 50% probability of failure (see Section 3.1.2.2). This assumption was employed in the TPD assessment to represent a weighted averaged probability of damage for each unique combination shown in Table 3.5 on uninspected 1947 pipe segments as well.

3.2.3 Third-Party Damage Failure Rate

The TPD large leak failure rate for the pipe segments in the road ROW was calculated by multiplying the hit rate and the probability of damage, given a hit for excavation damages. The excavation damages in combination with the farming damages failure rate for pipe segments in the farming land use became the total TPD large failure rate for the full pipelines. The pipe segments that are susceptible to either farming equipment (traverse the tilled land) or excavator failures (within the Road ROW) are shown in Fig.3.1 and Table 3.6.

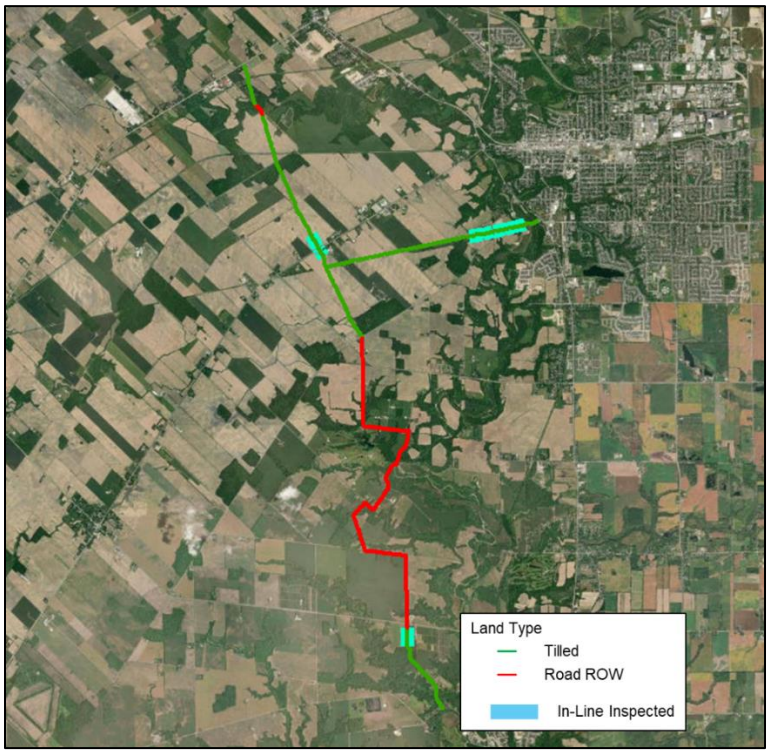


Figure 3.1 NPS 8 Port Stanley and NPS 8 St Thomas Pipelines - Land Type

Table 3.6: NPS 8 Port Stanley and NPS 8 St Thomas Pipelines Land Type and TPD Threat

Pipeline	Chainage (km)	Length (km)	% of Length	Land Type	Threat
NPS 8 Port Stanley	0 – 0.7	0.7	4.32	Tilled	TPD - Farming Equipment
	0.701 – 1.0	0.299	1.84	Road ROW	TPD - Excavator
	1.001 – 6.0	4.999	30.85	Tilled	TPD - Farming Equipment
	6.001 – 14.2	8.199	50.59	Road ROW	TPD - Excavator
	14.201-16.21	2.009	12.40	Tilled	TPD - Farming Equipment
NPS 8 St Thomas	0 – 4.41	4.41	100	Tilled	TPD - Farming Equipment

The failure mode of TPD-farming equipment and TPD-excavator is assumed to be large leak and the large leak failure rate was converted into an equivalent rupture rate using Equation O.4 in CSA Z662-23 Annex O [5]. As a result, the estimated large leak rates are 5.49E-05 and 2.33E-05 per km.yr, for NPS 8 Port Stanley and NPS 8 St Thomas pipelines, respectively, and the corresponding equivalent rupture failure rate are 3.93E-06 and 1.66E-06 per km.yr, respectively, as shown in Table 3.7.

Table 3.7: TPD Large Leak and Equivalent Rupture Failure Rates

Pipeline	Length (km)	Large Leak Failure Rate per km.yr	Equivalent Rupture Failure Rate per km.yr
NPS 8 Port Stanley	16.21	5.49E-05	3.93E-06
NPS 8 St Thomas	4.41	2.33E-05	1.66E-06

3.3 Compression Coupling and Aerial Crossing

According to the GIS records, 28 compression couplings and 2 aerial crossings were presented on the NPS 8 Port Stanley pipeline, while NPS 8 St Thomas pipeline has no compression couplings and aerial crossings. These compression couplings on NPS 8 Port Stanley pipeline were believed to be unrestrained in terms of the pipe vintage.

It is noted that both features could pose potential risks as a result of the possibility of pullout failures from compression couplings and large leaks/ruptures from aerial crossings. A comprehensive literature review of historical incident rates across GDS and PHMSA have been carried out and the preliminary results indicated that NPS 8 Port Stanley is likely to be susceptible to such risks due to the presence of these features. However, a more detailed analysis is required to quantify the risk in greater detail because of the limited knowledge of their failure mechanisms and lack of validated industrial failure rates. Additionally, line-specific parameters should also be accounted for to better predict the actual failure rate on NPS 8 Port Stanley pipeline. For instance, the frequency of natural forces along this line contributes to the failure rate of unrestrained compression couplings and the fact that the pipeline located in rural areas could affect the vehicle collision rate, which therefore influences the failure rate of aerial crossings.

While Enbridge is working on initiating projects to have a deeper understanding of both features, targeted initiatives and procedures such as the aerial crossing monitoring program and safe excavation procedures for compression coupling program were implemented in place to control these risks.

4. Tolerable Reliability Levels

4.1 Reliability Thresholds

The CSA Z662 Annex O standard provides guidance for operators to apply reliability-based thresholds to their pipeline systems for the LLS and ULS categories. The LLS and ULS reliabilities are calculated for each 100m segment.

The LLS reliability threshold for natural gas pipelines is recommended to be 1.0E-03 per km.yr based on a combination of leak impact analysis, historical leak rates, and calibration to ASME B31.8 and CSA Z662 [5].

The ULS reliability threshold for natural gas pipelines is developed by considering the risk of natural gas ignited releases on human safety. The consequences of natural gas pipeline failure are proportional to the population density ρ, probability of ignition, and the hazard area; since the probability of ignition is approximately proportional to the diameter D, and hazard area is proportional to PD^2 where P is the pipeline pressure, the reliability thresholds are defined as an increasing function of ρPD^3. Note that the NPS 8 Port Stanley and NPS 8 St Thomas pipelines are mainly located in the rural areas and the value of ρ for each 100m segment is calculated as the minimum of default (i.e 0.04) as per CSA

Z662 Class Location 1 [5] for segments without buildings within the potential impact radius (PIR) and the number of people resided in the buildings for the remaining segments. The resulting ULS thresholds on two pipelines are summarized in Table 4.1.

Table 4.1: Population Density and ULS Thresholds Estimation

Pipeline	Length (%)	MOP (psi)	Outside Diameter (in)	Population Density ρ per hectare	ULS Threshold per km.yr
NPS 8 Port Stanley	68.5	275	8	0.04	1E-03
	18.5	275	8	0.43	1E-03
	12.3	275	8	0.85	1E-03
	0.7	275	6	0.04	1E-03
NPS 8 St Thomas	90.7	275	8	0.04	1E-03
	9.3	275	8	1.98	1E-03

4.2 Segment Reliability

Failure rates for each individual 100 m segment are shown in Figures 4.1 - 4.4 for the LLS and ULS categories, respectively, along with their respective limits and targets for NPS 8 Port Stanley and NPS 8 St Thomas pipelines. The LLS limit and target have been set by adopting the Annex O LLS threshold as the limit (i.e., red line) and one order of magnitude lower than the limit as the target (i.e., green line). For ULS, the Annex O ULS threshold has been adopted as the limit and the Enbridge ULS threshold (1.0E-05 per km.yr) has been adopted as the target.

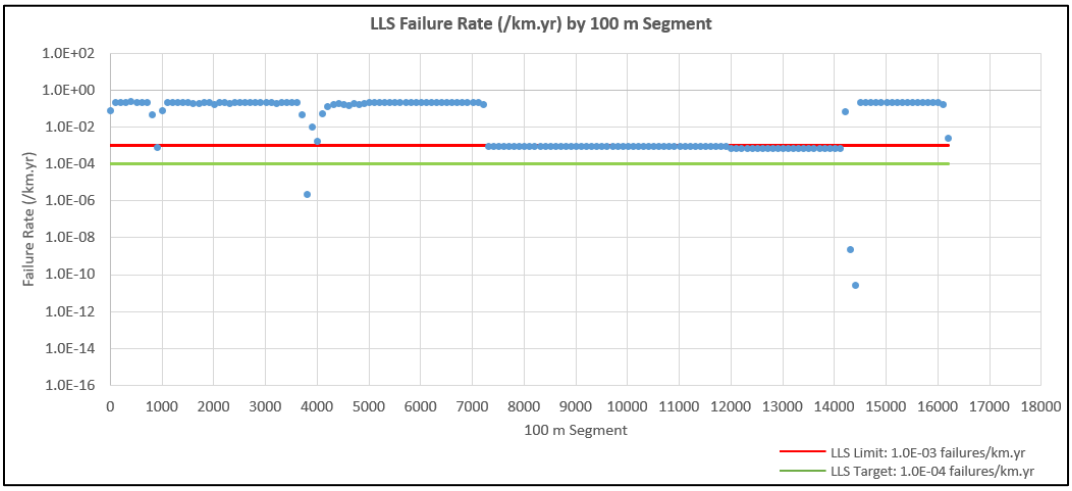


Figure 4.1: NPS 8 Port Stanley Pipeline - Annex O LLS Assessment

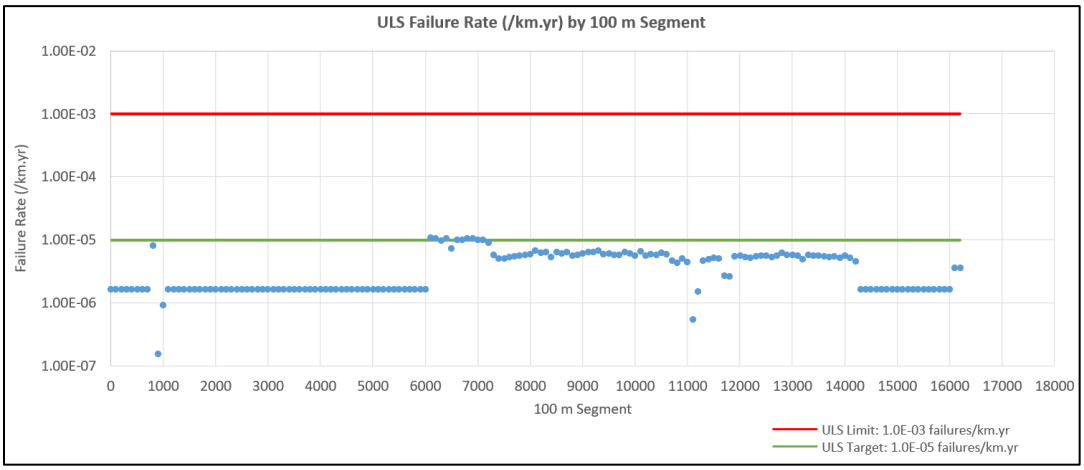


Figure 4.2: NPS 8 Port Stanley Pipeline - Annex O ULS Assessment

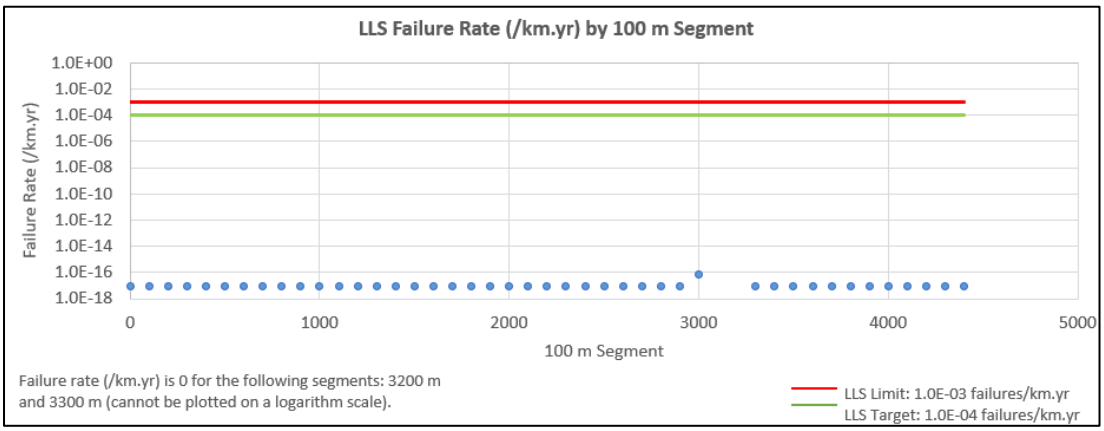


Figure 4.3: NPS 8 St Thomas Pipeline - Annex O LLS Assessment

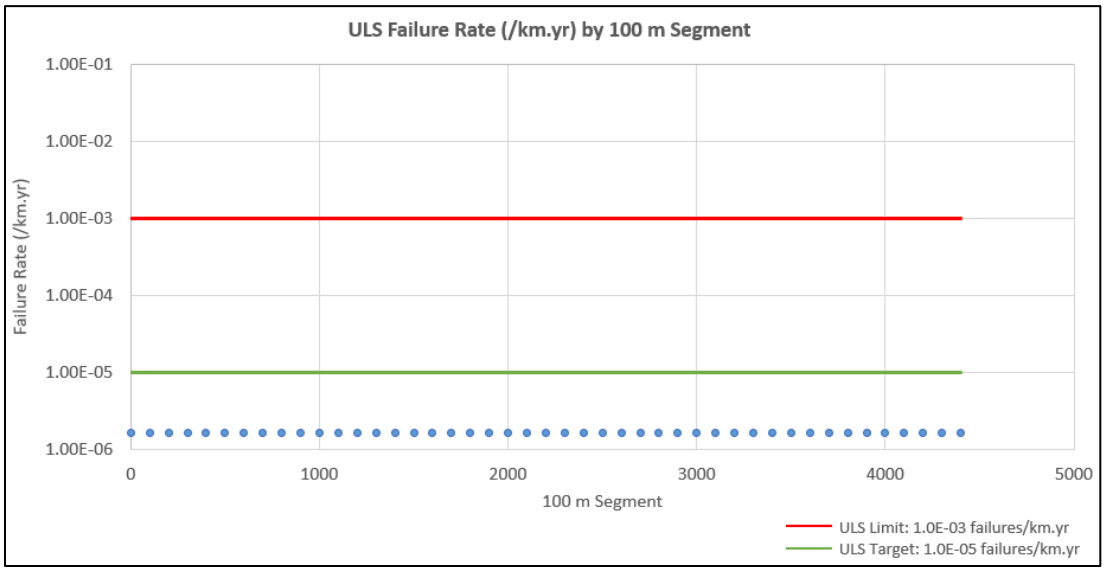


Figure 4.4: NPS 8 St Thomas Pipeline – Annex O ULS Assessment

For the NPS 8 St Thomas pipeline, all 100m segments are below LLS Target and ULS Target. For the NPS 8 Port Stanley pipeline, it is noted that three 100m segments are located much lower than the LLS Target on the LLS plot and this is attributed to the calculated low inspected corrosion failure rates on these segments (i.e. 3800-3900m, 14300-14400m, and 14400-14500m). Note further that post-2000 modern segments (7300 – 10900m) are actually below the LLS Limit on the graph, while other segments are above or close to the LLS Limit as a result of the high values of PYRAMID (1970-2000 pipe segments) or bootstrapping (pre-1970 segments). On the other hand, all segments of NPS 8 Port Stanley are below the ULS Limit.

The corrosion leak rates in the near future are estimated to be 1.7E-03 and 1.01E-17 per km.yr for NPS 8 Port Stanley and NPS 8 St Thomas pipelines, respectively.

4.3 Reliability Maps

Figures 4.5 and 4.6 show the reliability of the pipeline based on the LLS and the ULS, respectively, with 100 m segmentation granularity. Colouring has been applied based on each limit state's respective limit and target.

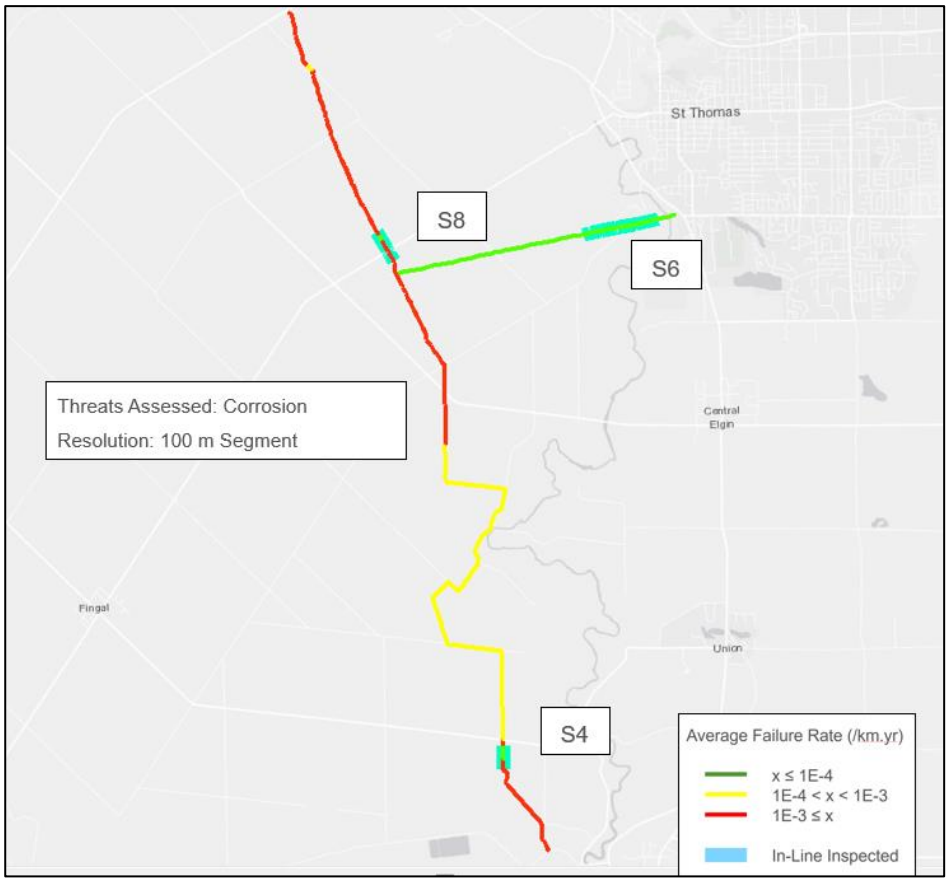


Figure 4.5: NPS 8 Port Stanley and NPS 8 St Thomas Pipelines - LLS Map (100 m Segments)

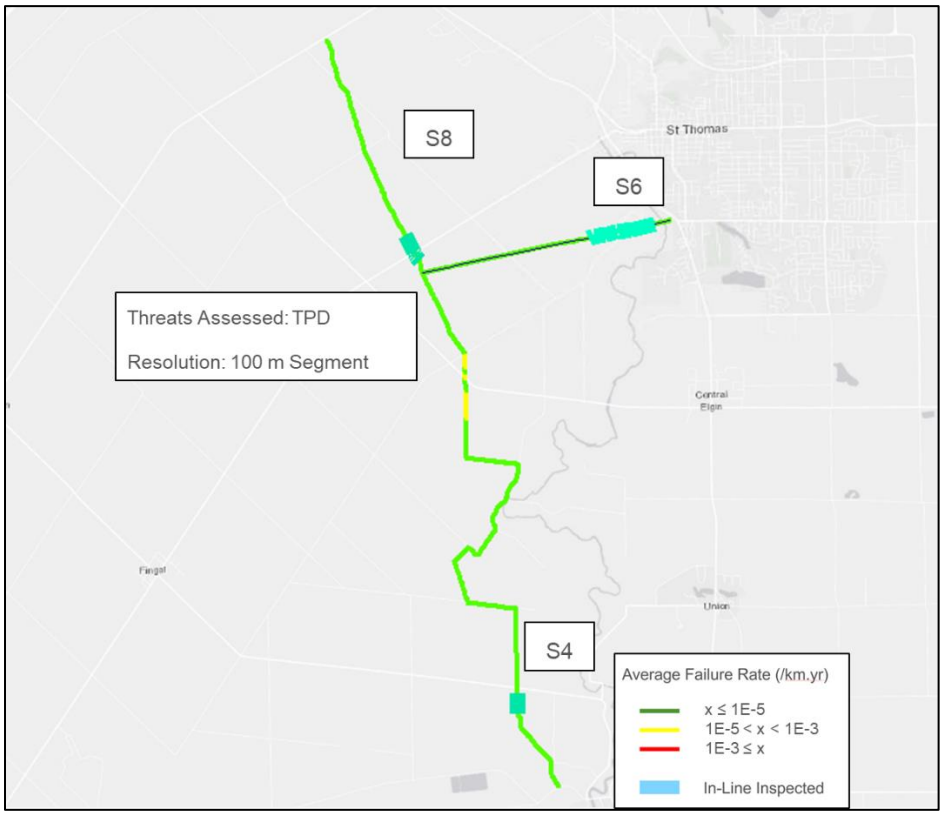


Figure 4.6: NPS 8 Port Stanley and NPS 8 St Thomas Pipelines - ULS Map (100 m Segments)

Figure 4.7 shows the overall reliability of the pipeline by combining the LLS and ULS categories as assessed against their respective limits and targets. The combined reliability map is coloured based on the worst-case reliability level from either the LLS or ULS map (i.e., “Above Limit” means that either the LLS or ULS limit was exceeded).

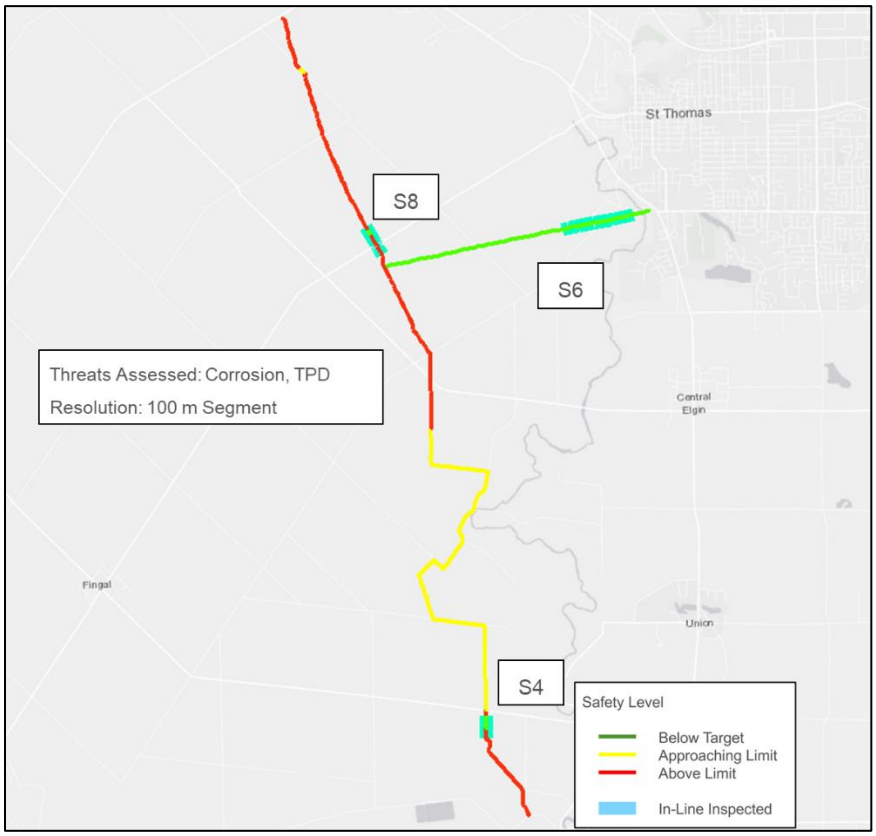


Figure 4.7: NPS 8 Port Stanley and NPS 8 St Thomas Pipelines - Combined Map (100 m Segments)

5. Enbridge Operational Risk Assessment Matrix Mapping

The Enbridge Operational Risk Assessment Matrix was applied to the assessment of scenarios that could result in health and safety impacts to the public, customer disruption, or financial losses. The risk matrix was performed by leveraging the assessed reliability in Section 3 with additional conditional probabilities that a given outcome will occur and potential consequences resulting from the scenario. The consequences were determined by consulting with SMEs and incorporating data-driven models, where available. The full scope of the NPS 8 Port Stanley and NPS 8 St Thomas pipelines were applied in mapping the scenarios to the risk matrix.

5.1 Health & Safety Risk

5.1.1 Health & Safety Outcome 1 (HS1) - Migration and Explosion of Nearby Structure

Pipeline leaks may pose a significant health and safety risk if gas migrates into a nearby building and causes an explosion. In this scenario, an underground leak migrates through the soil or via below-ground infrastructure, reaches an enclosed area or structure, accumulates to ignitable gas concentrations, and encounters an ignition source.

Due to its proximity to multiple nearby buildings, in the event of a small or large leak, the NPS 8 Port Stanley and NPS 8 St Thomas pipelines are considered susceptible to gas migration and explosion.

5.1.1.1 HS1 Probability

The probability of a migration and explosion event was determined by multiplying the probability of a failure (segment lengths which are actually within a 75m distance of a building) by the conditional probability that the leak may migrate into a nearby building and cause an explosion as shown in Table 5.1. The conditional probabilities of migration-explosion have been determined though a review of migration-related ignitions in the PHMSA incident repository and represent system-wide averages. Note that corrosion and TPD have their individual conditional probabilities. The full details of the approach to determine condition probabilities of migration-explosion are outlined in Section 5.1.1 in the DIMP RAD [4].

It is noted that only 18% and 11% of 100m segments on NPS 8 Port Stanley and NPS 8 St Thomas pipelines, respectively, is within a 75 m distance of a building, while segments not located near a building contribute zero to the health and safety risk regarding gas migration and explosion. Combining the conditional probability of migration-explosion, probability of failure and the percentage of length that is within 75m of a building for each 100m segment, the final probability of a migration and explosion event on the NPS 8 Port Stanley and NPS 8 St Thomas pipelines are 2.99E-05 and 2.09E-09 events/yr, respectively.

Table 5.1: Probability of Migration and Explosion

Pipeline	Threat	Probability of Migration and Explosion Given a Failure (Industry Average for Steel Mains)	Probability of Failure (/yr)	Probability of Migration and Explosion (/yr)
NPS 8 Port Stanley	Corrosion (Small Leak)	1.79E-04	1.87	2.99E-05
	TPD (Large Leak)	4.09E-04	8.90E-04	6.64E-08
Total				**2.99E-05**
NPS 8 St Thomas	Corrosion (Small Leak)	1.79E-04	4.47E-17	3.57E-22
	TPD (Large Leak)	4.09E-04	1.03E-04	2.09E-09
Total				**2.09E-09**

5.1.1.2 HS1 Consequence

The NPS 8 Port Stanley and NPS 8 St Thomas pipelines are in close proximity to some residential, commercial, and office buildings. Based on a satellite imagery survey commissioned by Enbridge Gas [6], there are 25 and 4 buildings within 75 m of the NPS 8 Port Stanley and NPS 8 St Thomas pipelines, respectively, in which a migration-explosion event is possible. The consequences due to health and safety are qualitatively estimated based on its location and Section 5.3.1 in the DIMP RAD [4] and are shown in Table 5.2.

Table 5.2: Fatality Risks of a Migration and Explosion Event

Estimate	Fatality		Justification
	NPS 8 Port Stanley	NPS 8 St Thomas	
Minimum	0.5	0.5	The minimum fatality consequence assumes an explosion in an unoccupied structure, likely only resulting in possible injuries.
Most Likely	1	1	The best estimate for fatality consequence for a mix of residential, multi-residential, and commercial structures.
Maximum	2	2	The maximum fatality consequence assumes a failure near a larger office, commercial buildings, or religious facilities. It also includes failures in buildings which may take longer to evacuate such as schools or health care settings.

5.1.2 Health & Safety Outcome 2 (HS2) - Local Ignition at Failure Site

Large leaks may also pose a significant health and safety risk through immediate or delayed ignition near the source of the failure. In this scenario, ignition may occur immediately if sufficient kinetic energy is present in the initial moment of burst, or after a slight delay until the gas encounters a nearby ignition source (e.g., excavation equipment). Both jet fires and flash fires have been observed in industry on distribution pipelines.

5.1.2.1 HS2 Probability

The probability of a local ignition event was determined by multiplying the probability of a failure by the conditional probability that the large leak ignites as shown in Table 5.3. The probability of local ignition at the failure site can be estimated by calculating the expected mass flowrate of gas following failure described in Section 5.2 in the DIMP RAD [4] and using the ignition probabilities for an urban release listed in the OGP Report 434-6.1 [7]. The probability of a local ignition event on the NPS 8 Port Stanley and NPS 8 St Thomas pipelines are 1.60E-06 and 1.85E-07 events/yr, respectively.

Table 5.3: Probability of Local Ignition

Pipeline	Threat	Release Rate (kg/s)	Probability of Local Ignition Given a Failure	Probability of Failure (/yr)	Probability of Local Ignition (/yr)
NPS 8 Port Stanley	Large Leak	4.13	1.80E-03	8.90E-04	1.60E-06
Total					**1.60E-06**
NPS 8 St Thomas	Large Leak	4.13	1.80E-03	1.03E-04	1.85E-07
Total					**1.85E-07**

5.1.2.2 HS2 Consequence

The health and safety consequences of a local ignition event can vary from injuries to fatalities depending on the magnitude of the fire and the number and vulnerability of people present. The consequence is qualitatively estimated as shown in Table 5.4.

Table 5.4: Fatality Risks of a Local Ignition Event

Estimate	Fatality		Justification
	NPS 8 Port Stanley	NPS 8 St Thomas	
Minimum	0.5	0.5	No fatalities and possible injuries.
Most Likely	1	1	The best estimate for fatality consequence assumes a failure with an exposed individual present (likely during excavation activities).
Maximum	2	2	The maximum fatality consequence assumes a failure affecting a populated area along the pipelines

5.1.3 Health & Safety Risk - Operational Risk Assessment Matrix Mapping

The results of the assessed health and safety risk outcomes for the full scope of the NPS 8 Port Stanley and NPS 8 St Thomas pipelines are shown in Figure 5.1.

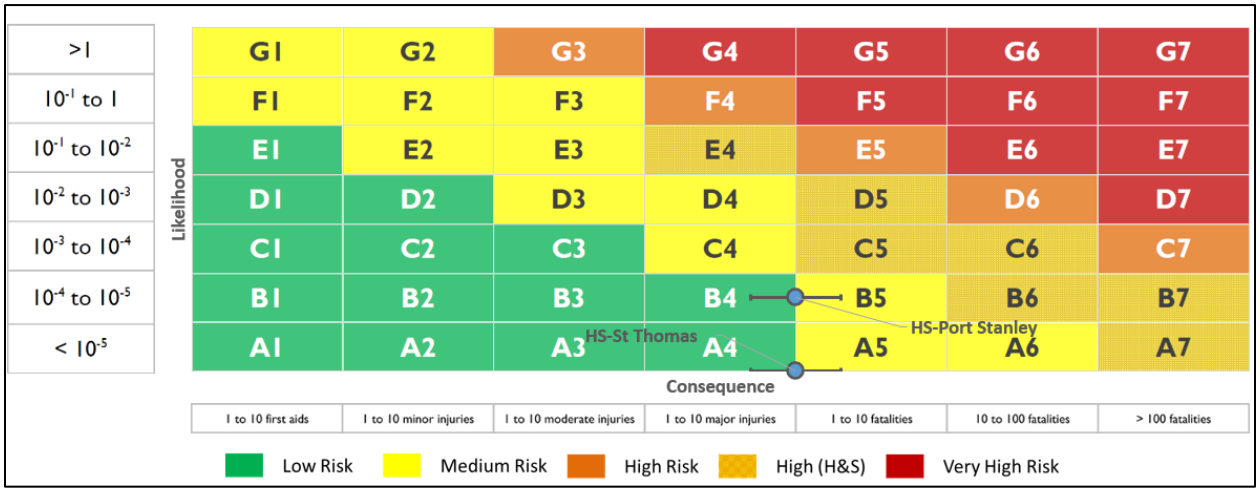


Figure 5.1: Enbridge Operational Risk Assessment Matrix - Health & Safety Risk

5.2 Operational Disruption Risk

5.2.1 Operational Disruption Outcome 1 (OD1) - Customer Losses Due to Operational Disruptions

In an emergency where a leak on a pipeline is confirmed, Enbridge's top priority is to perform "Make Safe" actions to protect its workers and the public from harm. Enbridge will also consider any possible environmental impacts of a large leak on the pipeline to ensure it meets its Environmental, Social, and Governance (ESG) commitments. Based on a case-by-case assessment, it may be required to perform an immediate isolation of the hazardous pipe segment by closing nearby valves or restricting the gas flow, resulting in potential customer loss.

The number of customer loss derived from DOE team indicates that the first 4500m of NPS 8 Port Stanley pipeline has a comparatively higher number of customer loss compared to the remaining pipeline lengths, which suggests that NPS 8 Port Stanley pipeline should be broken down into two sections and evaluated the risk individually. On the other hand, NPS 8 St Thomas pipeline has a constant value of customer loss across the whole line as per DOE and therefore only one dot will be drawn on the risk matrix below.

5.2.1.1 OD1 Probability

The probability of an operational disruption event on NPS 8 Port Stanley pipeline was determined by multiplying the probability of a failure by the conditional probability that the failure would lead to an operational disruption as shown in Table 5. For the large leak as a result of TPD, the conditional probability of 80% was employed as per SME. For the small leak induced by corrosion, the conditional probability included a series of assumptions: the pipeline shutdown was considered only when the leak occurred on a pipe segment installed in 1947 within a building of 50m that wasn't able to be repaired by skinner clamp or sleeve during the winter time. These assumptions were proposed because NPS 8 Port Stanley pipeline was in poor condition that finding a weldable position to weld stoppers and bypass close to the leak location was challenging as per SME. As such, the probability of an operational disruption event on the NPS 8 Port Stanley pipeline are 1.12E-02 and 8.98E-03 events/yr, respectively, for the 0-4500m and 4600-16300m, as shown in Table 5.5. The results indicate that the pipe segment (0 – 4500m) is in the high risk cell (E6) while the pipe segment (4600 – 16300m) lies in the medium risk cell (D5).

Table 5.5: Probability of Operational Disruption of NPS 8 Port Stanley Pipeline

Assumptions	Pipe Sections		Sources
	0 – 4500m	4600 – 16300m	
Corrosion failure rate (/yr)	8.35E-01	1.03	QRA
Percentage of pipe length within any buildings 75m contour	6.85%	5.59%	ArcMap
Probability of corrosion leak occurring in peak winter	40%	40%	SME
Probability of clamp failure as a repair option	75%	75%	Operation
Probability of sleeve failure as a repair option	71.4%	71.4%	SME

Percentage of vintaged (pre-1970) pipe length over pipe length within any buildings 75m contour	63%	33%	ArcMap
Probability of Small Leak Operational Disruption (/yr)	1.12E-02	9.89E-03	
TPD failure rate (/yr)	1.09E-04	7.81E-04	QRA
Probability of Large Leak Operational Disruption Given Failure	80%	80%	SME
Probability of Large Leak Operational Disruption (/yr)	8.70E-05	6.25E-04	
Probability of Total Operational Disruption (/yr)	1.12E-02	9.89E-03	

On the other hand, although the NPS 8 St Thomas pipeline is connected to the NPS 8 Port Stanley pipeline, it is in significantly better condition. Using conservative simplifying assumptions of 10% and 80% as the probability of an operational disruption for small leak and large leak, respectively, the probability of operational disruption on the NPS 8 St Thomas pipeline is conservatively estimated to be 8.21E-05 as shown in Table 5.6.

Table 5.6: Probability of Operational Disruption of NPS 8 St Thomas Pipeline

Pipeline	Threat	Probability of Operational Disruption Given Failure	Probability of Failure (/yr)	Probability of Operational Disruption (/yr)
NPS 8 St Thomas	Small Leak	0.1	4.47E-17	4.47E-18
	Large Leak	0.80	1.03E-04	8.21E-05
	Total			**8.21E-05**

5.2.1.2 OD1 Consequence

Customers that are reliant on this pipeline system include those in residential and commercial buildings, who count on a reliable, dependable energy source for their daily operations. A review of gas demand has been completed to assess the customer impact of a service shutdown (i.e., isolation using mainline valves) on the NPS 8 Port Stanley and NPS 8 St Thomas pipelines for a range of scenarios including 0 degree day (summer), fall peak, and design day. In addition to the outside temperature, the location at which the failure occurs along the pipeline can impact the number of customer losses, resulting in a large range of possible outcomes. An assessment of the operational disruption consequences was completed by comparing the simulated customer loss scenarios with the business-unit specific operational disruption consequence criteria as shown in Table 5.7.

Table 5.7 Operational Disruption Customer Loss

Estimate	Customer Loss Consequence			Justification
	NPS 8 Port Stanley		NPS 8 St Thomas	
	0 – 4500m	4600 – 16300m		
Minimum	2700 (Category 5)	2200 (Category 5)	50 (Category 2)	Isolation in the event of an emergency for a 0 degree day (summer) scenario.
Most Likely	15606 (Category 6)	2800 (Category 5)	12806 (Category 6)	Isolation in the event of an emergency for a fall peak scenario.
Maximum	18906 (Category 6)	2850 (Category 5)	16806 (Category 6)	Isolation in the event of an emergency for a design day scenario.

5.2.2 Operational Disruption Risk - Operational Risk Assessment Matrix Mapping

The results of the assessed operational disruption risk outcome for the full scope of the NPS 8 Port Stanley and NPS 8 St Thomas pipelines are shown in Figure 5.2.

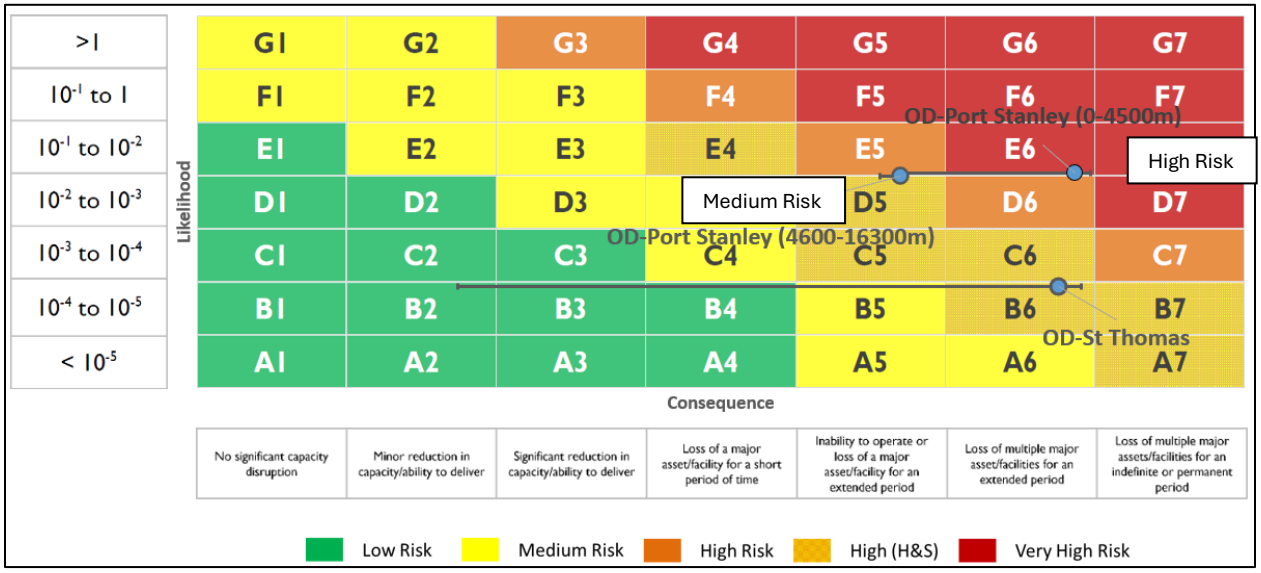


Figure 5.2: Enbridge Operational Risk Assessment Matrix - Operational Disruption Risk

5.3 Financial Risk

5.3.1 Financial Outcome 1 (F1) - Small Leak Resulting in Pipeline Repair or Replacement

The highest financial risk is associated with the scenario of a small leak on the NPS 8 Port Stanley and NPS 8 St Thomas pipelines where an immediate repair of the pipeline is necessary and will result in repair costs including planning, permitting, excavation, and materials. Given the immediate need for the repair, the emergency nature of the work will increase the costs in comparison to the same work completed on a planned basis due to expedited planning and permitting requirements and overtime work. In addition, timing of the repair cannot be planned to minimize gas demands resulting in the possibility of performing a repair at a time of the year with high gas demands, requiring installation of larger bypass piping (if bypass is possible) to mitigate any customer impacts.

5.3.1.1 F1 Probability

The probability of a pipeline repair is the product of the small leak failure rate and the total length of the pipeline, which is calculated to be 1.87 and 4.47E-17 events/yr on the NPS 8 Port Stanley and NPS 8 St Thomas pipelines, respectively.

5.3.1.2 F1 Consequence

Given that the costs of a leak can vary based on the repair type, it is assumed that a probability of 25% is applied to repair a leak using a clamp because the Operations group has responded to four leaks so far this year, and only one was successfully repaired with a clamp in the Winsor region as per SME, and the consequences are presented as a range of values as shown in Table 5.8.

Table 5.8 Pipeline Repair Costs of Corrosion Leak

Estimate	Value ($)	Justification
Most Likely	$50,000	Assumes the repair type is a clamp.
Minimum	$250,000	Assumes the pipe needs to be replaced.
Most Likely	$1,000,000	
Maximum	$2,000,000	

5.3.2 Financial Risk - Operational Risk Assessment Matrix Mapping

The result of the assessed financial risk outcome for the full scope of the NPS 8 Port Stanley and NPS 8 St Thomas pipelines is shown in Figure 5.3. It should be noted that the actual likelihood for NPS 8 St Thomas pipeline is 4.41E-17 which is markedly lower than the minimum bound of the Risk Matrix; in this case the point on the Risk Assessment Matrix is for visualization only.

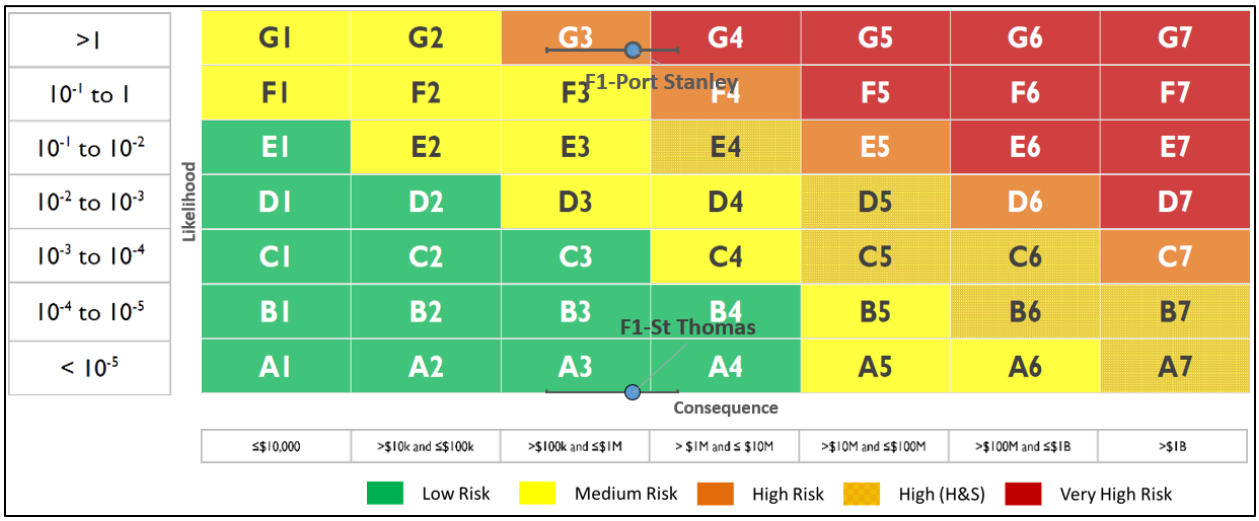


Figure 5.3: Enbridge Operational Risk Assessment Matrix - Financial Risk

6. Recommendations

A risk assessment utilizing a defense-in-depth approach was conducted to evaluate the reliability and risk of the NPS 8 Port Stanley and NPS 8 St Thomas pipelines considering corrosion and TPD threats to its pipeline integrity.

Failure rates were calculated based on historical information and best practice reliability models and then compared to industry benchmarks. Based on best available data at the time of the assessment, the current assessment concludes:

- 8.9 km of the 16.21 km pipeline (55%) on NPS 8 Port Stanley pipeline is assessed to have a small leak failure rate above the 1.0E-03 per km.yr LLS limit described by CSA Z662 Annex O.
- All pipe segments on NPS 8 St Thomas pipeline are associated with small leak failure rate below the 1.0E-04 per km.yr LLS target described by CSA Z662 Annex O.
- 0 km of the 16.21 km pipeline (0%) on NPS 8 Port Stanley and 0 km of the 4.41 km pipeline (0%) on NPS 8 St Thomas pipelines are assessed to have a large leak (or equivalent rupture) failure rate above the 1.0E-03 per km.yr ULS limit described by CSA Z662 Annex O for an NPS 8 pipeline at 175 psi MOP in a Class 1 (rural) location.
- Integrating the LLS and ULS approaches, 8.9 km of the 16.21 km pipeline (55%) on NPS 8 Port Stanley fails one reliability limit, with the driver of corrosion.

In addition, risks placed on the 7x7 Enbridge Operational Risk Assessment Matrix indicate that portions of the Port Stanley pipeline meet the definition of “High Risk”.

It is noted that the current assessment is **highly influenced by the uncertainty due to small ILI sample size and uncertainty in the wall thickness of the pipeline**. Thus, while estimates based on current based available information suggest that high risks may be present on Port Stanley, it is recommended that further information be gathered on the pipeline to confirm current conclusions.

It is also noted that the above assessment accounts for TPD and corrosion only, while the existence of compression couplings and aerial crossings on NPS 8 Port Stanely may pose additional risk on the overall assessment in Health & Safety, Financial and Operation risks. While the aerial crossing assessment program and safe excavation procedures have been established to control these risks, it is recommended that additional detailed analysis be performed on these two threats to better approach the actual risk posed on these lines.

References

[1] Enbridge Gas Inc. (2024). *Quantitative Risk Assessment (QRA) - St. Laurent North Pipeline* (EB-2024-0200, Exhibit B, Tab 1, Schedule 1, Attachment 2). Ontario Energy Board.

[2] Integrity Assessments Department - Enbridge Gas Transmission and Midstream, Enbridge Inc., "Asset Integrity Risk Algorithm Document (RAD)," 2023.

[3] C-FER Technologies, "Next Generation Third-party Mechanical Damage Hit Rate Model," Edmonton, 2023.

[4] Integrity Assessments - Enbridge Gas Inc. (2021). *PRIM Distribution Risk Model - Risk Algorithm Document*. Internal document: unpublished.

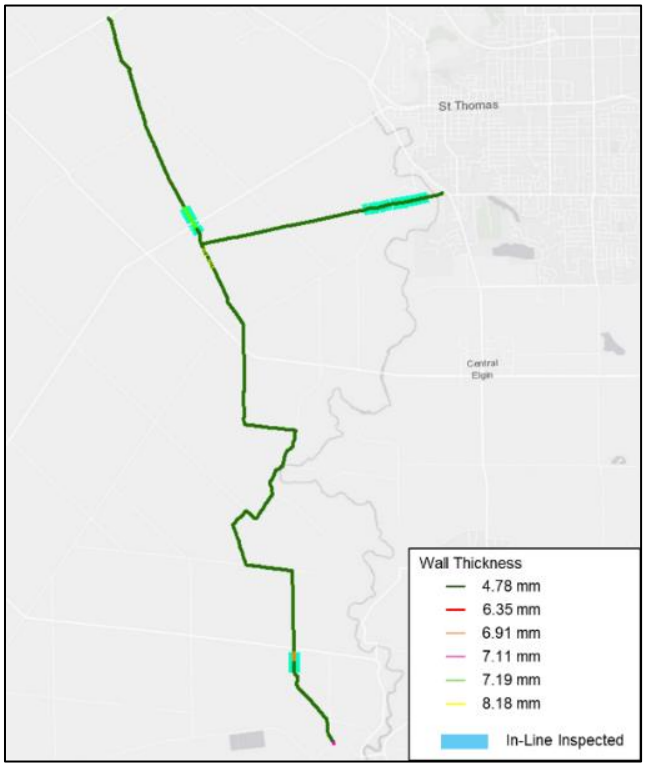
[5] Canadian Standard Association. (2023). *CSA Z662:23 Oil and Gas Pipeline Systems - Annex O Reliability-based design and assessment (RBDA) of onshore non-sour service natural gas transmission and LVP liquid hydrocarbon pipelines* (CSA Z662:23).

[6] Integrity Assessments - Enbridge Gas Inc. (2023). Enertech Building Footprints and Human Occupancy Dataset [File Geodatabase].

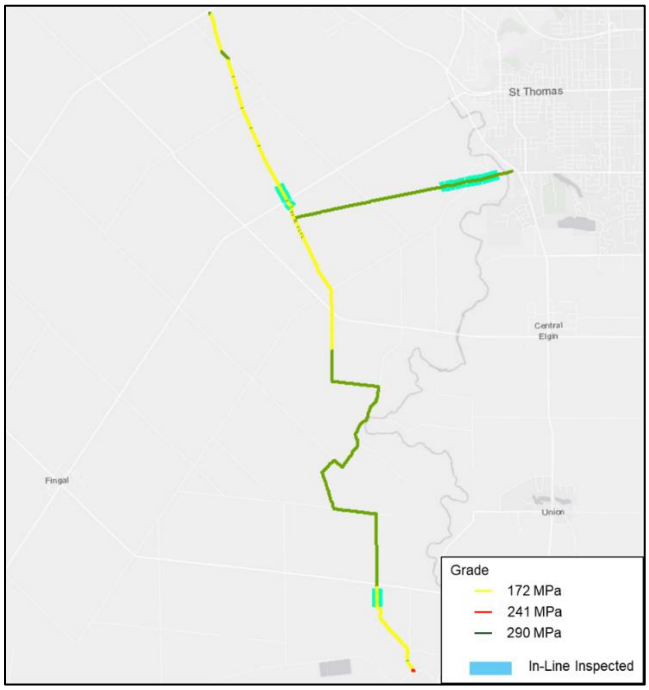
[7] International Association of Oil & Gas Producers. (2010). *OGP Risk Assessment Data Directory - Ignition Probabilities* (Report No. 434 – 6.1).

Appendix A: Pipeline Characteristics Maps

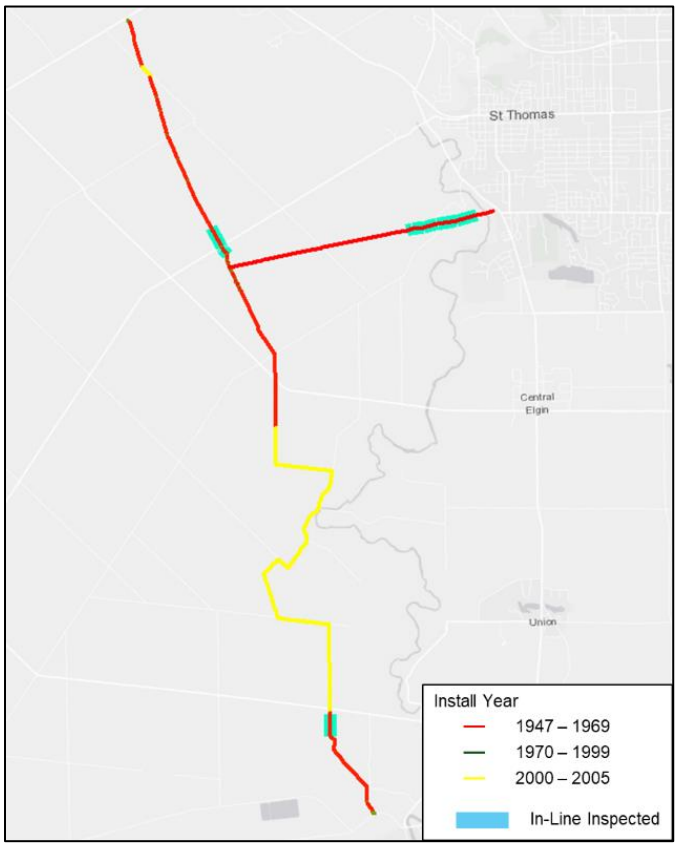
Wall Thickness



Grade



Install Year



ENBRIDGE

Appendix B: Leak Record on NPS 8 Port Stanley Pipeline

OD-R16499XM-01 TRANSMISSION M A O P SYSTEM - 62
LEAK DATA REPORT

PORT STANLEY LINE

MILE POINT	SIZE	DATE REPAIRED	L.R.O. #	LEAK CAUSE	MAIN OR SERVICE	STEEL / CAST	PRES SURE	JOINT TYPE	COATING	COAT CDN	SOIL TYPE	PITT ING	PEN	SCA LE	LOCA TION	REPAIR NO. 1	REPAIR NO. 2	REPAIR NO. 3
5.3712	8.00	00-06-70	6330	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	SHAL	TOP	HARD	PIPE	*	CLAMP	OTHER
5.3769	8.00	00-06-70	6331	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	ALL	HARD	PIPE	*	*	OTHER
5.4047	8.00	04-06-70	A39158	CORR	MAIN	STEEL	HP		*	*	CLAY	SHAL	TOP	HARD	PIPE	CLAMP	*	*
5.4492	8.00	00-06-70	6332	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	ALL	HARD	PIPE	*	*	OTHER
5.4511	8.00	00-06-70	6333	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
5.4591	8.00	00-06-70	6334	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	*
5.4597	8.00	09-06-70	A39156	CORR	MAIN	STEEL	HP		*	*	CLAY	DEEP	ALL	HARD	PIPE	OTHER	*	*
5.4875	8.00	00-06-70	6335	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
5.4958	8.00	00-04-62	6336	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
5.4962	8.00	00-12-63	6337	CORR	MAIN	STEEL	HP		* BARE	*	S LOAM	*	*	*	PIPE	*	*	CLAMP
	8.00	00-01-64	6338	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	SADDLE
5.5320	8.00	23-06-70	A39155	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	ALL	HARD	PIPE	OTHER	*	*
5.5341	8.00	09-06-70	A39200	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	*	OTHER	*	*
5.5426	8.00	02-06-70	A39199	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	DRESER	OTHER	*
5.5680	8.00	25-06-70	A39198	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	*
5.6089	8.00	00-06-70	6339	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
5.6349	8.00	23-06-70	A39197	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
5.8333	8.00	00-05-61	6340	CORR	MAIN	STEEL	HP		*	*	SAND	*	*	*	PIPE	*	*	CLAMP
6.0261	8.00	00-07-59	6341	CORR	MAIN	STEEL	HP		* BARE	*	SAND	*	*	*	*	*	*	SADDLE
6.0809	8.00	00-06-70	6342	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	ALL	HARD	PIPE	*	*	OTHER
6.0911	8.00	10-06-70	A39196	CORR	MAIN	STEEL	HP		*	*	CLAY	DEEP	ALL	HARD	PIPE	OTHER	*	*
6.5536	8.00	12-06-70	A39195	CORR	MAIN	STEEL	HP		*	*	CLAY	DEEP	ALL	HARD	PIPE	OTHER	*	*
6.5642	8.00	00-06-70	6344	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	ALL	HARD	PIPE	*	*	OTHER
6.5691	8.00	00-06-70	6345	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	ALL	HARD	PIPE	*	*	OTHER
6.5739	8.00	00-06-70	6346	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	ALL	HARD	PIPE	*	*	OTHER
8.4981	8.00	00-03-60	6347	*	MAIN	STEEL	HP		* BARE	*	SAND	*	*	*	*	*	*	OTHER
8.5985	8.00	00-10-70	6348	BREAK	MAIN	STEEL	HP		* BARE	*	SAND	*	*	*	PIPE	*	*	SLEEVE
8.7292	8.00	00-10-70	6349	OTHER	MAIN	STEEL	HP		* BARE	*	SAND	*	*	*	OTHER	*	*	CLAMP
9.0292	8.00	00-11-67	6350	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
9.7458	8.00	02-07-70	008531	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	ALL	MED	PIPE	OTHER	WELD	*

OD-R16499XM-01 TRANSMISSION M A O P SYSTEM - 62
LEAK DATA REPORT

PORT STANLEY LINE

MILE POINT	SIZE	DATE REPAIRED	L.R.O. #	LEAK CAUSE	MAIN OR SERVICE	STEEL / CAST	PRES SURE	JOINT TYPE	COATING	COAT CDN	SOIL TYPE	PITT ING	PEN	SCA LE	LOCA TION	REPAIR NO. 1	REPAIR NO. 2	REPAIR NO. 3
.2968	8.00	29-03-72	081687	MECH	MAIN	STEEL	HP	DRESER	C.T.	GOOD	CLAY	NIL	*	*	DRESER	SLEEVE	*	*
.7555	8.00	00-11-62	6284	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	CLAMP	SADDLE
1.1193	8.00	00-12-60	6285	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
1.1212	8.00	00-04-61	6286	CORR	MAIN	STEEL	HP		*	*	CLAY	*	*	*	PIPE	*	CLAMP	CLAMP
1.1364	8.00	00-05-64	6287	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	CLAMP	CLAMP	SADDLE
1.1553	8.00	00-06-62	6288	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
1.3826	8.00	00-11-62	6289	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
1.4366	8.00	00-03-61	6290	CORR	MAIN	STEEL	HP		*	*	CLAY	*	*	*	PIPE	*	*	CLAMP
1.8910	8.00	21-04-71	053898	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	CLAMP	ANODE	*
2.0379	8.00	00-08-63	6291	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	SADDLE
2.2803	8.00	00-09-61	6292	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
2.4943	8.00	00-01-60	6293	*	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	*	*	*	CLAMP
2.7559	8.00	00-11-71	6294	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	MED	PIPE	*	*	CLAMP
2.7804	8.00	16-06-70	A39193	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.7867	8.00	02-07-70	008530	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	ALL	HARD	PIPE	OTHER	WELD	*
2.8000	8.00	00-06-62	6297	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
2.8030	8.00	00-06-70	6298	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.8056	8.00	03-06-70	A39194	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.8066	8.00	02-06-70	A39192	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.8091	8.00	00-06-62	6299	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	SADDLE
2.8119	8.00	00-06-70	6300	CORR	MAIN	STEEL	HP		*	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.8146	8.00	00-06-70	6301	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.8157	8.00	02-06-70	A39154	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.8220	8.00	00-06-70	6302	CORR	MAIN	*	*		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.8350	8.00	02-06-70	A39151	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.8409	8.00	00-06-70	6303	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.8413	8.00	00-06-70	6304	CORR	MAIN	STEEL	HP		*	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.8416	8.00	04-06-70	A39161	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.8443	8.00	02-06-70	A39152	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.8449	8.00	00-06-70	6305	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.8473	8.00	00-06-62	6306	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
2.8506	8.00	00-06-70	6307	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.8593	8.00	00-06-62	6308	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
2.8597	8.00	00-04-67	6309	CORR	MAIN	*	*		* BARE	*	CLAY	*	*	*	PIPE	*	*	SADDLE
2.8785	8.00	17-05-83	A89054	CORR	MAIN	STEEL	HP	WELD	BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.8804	8.00	14-04-81	A80145	CORR	MAIN	STEEL	HP	DRESER	BARE	*	CLAY	DEEP	BOT	HARD	PIPE	CLAMP	*	*
2.8831	8.00	02-06-70	A39153	CORR	MAIN	STEEL	HP		*	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.8856	8.00	00-01-67	6310	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	SADDLE
2.8894	8.00	00-06-70	6311	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.9320	8.00	00-06-70	6312	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.9405	8.00	00-06-70	6313	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.9446	8.00	02-06-70	A39160	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.9532	8.00	02-06-70	A39159	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	OTHER	*	*
2.9675	8.00	04-06-70	A39191	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	CLAMP	*	*
2.9731	8.00	00-09-68	6314	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	SADDLE
2.9739	8.00	00-06-70	6315	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	OTHER
2.9981	8.00	00-08-61	6316	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
3.1078	.00	00-01-62	6317	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
3.1080	8.00	00-06-61	6318	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	SADDLE
3.2180	8.00	00-06-70	6319	CORR	MAIN	STEEL	HP		*	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	CLAMP
3.3845	8.00	00-09-62	6320	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
3.4091	8.00	00-01-60	6321	*	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	*	*	*	CLAMP
3.8826	8.00	00-08-61	6322	CORR	MAIN	STEEL	HP		* BARE	*	S LOAM	*	*	*	PIPE	*	*	CLAMP
4.0646	8.00	00-11-70	6323	CORR	MAIN	STEEL	HP		*	*	GRAVEL	DEEP	TOP	HARD	PIPE	*	*	CLAMP
4.2636	8.00	00-04-62	6324	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
4.6780	8.00	00-04-61	6325	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	*	*	*	PIPE	*	*	CLAMP
4.7727	8.00	00-06-70	6326	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	CLAMP
4.8591	8.00	00-11-70	6327	CORR	MAIN	STEEL	HP		*	*	CLAY	*	*	*	PIPE	*	*	CLAMP
4.8902	8.00	00-06-70	6328	*	*	*	*	*	*	*	*	*	*	*	*	*	*	OTHER
4.8903	8.00	26-06-70	A39157	*	MAIN	STEEL	HP		*	*	*	*	*	*	*	OTHER	*	*
4.9053	8.00	00-06-70	6329	CORR	MAIN	STEEL	HP		* BARE	*	CLAY	DEEP	BOT	HARD	PIPE	*	*	CLAMP
5.2473	8.00	27-10-70	053784	CORR	MAIN	STEEL	HP		* BARE	*	S LOAM	SHAL	TOP	HARD	PIPE	CLAMP	*	*

Appendix C: TPD Mechanical Damage Hit Rate Model

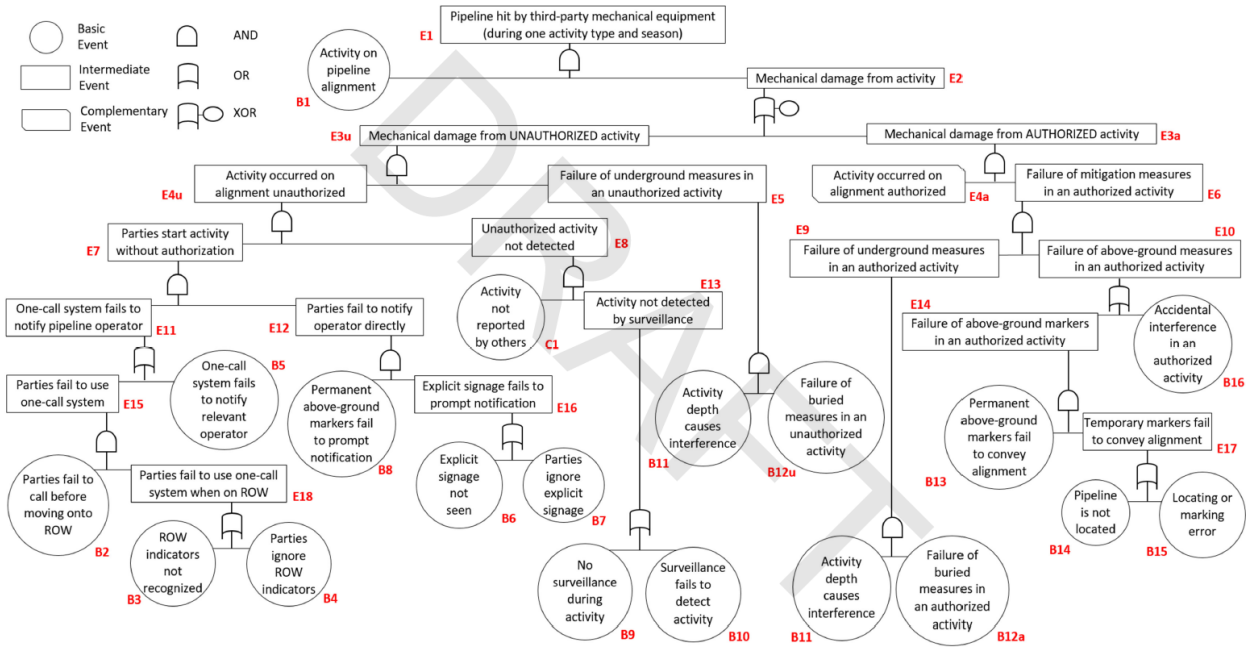


Figure C.1: C-FER TPD Mechanical Damage Hit Rate Model - Fault Tree [3]

Table C.1: Probability Values for Fault Tree Modelling [3]

Factor	Event	Conditions	Probability
B1	Activity on pipeline alignment	Based on EGI modified approach using XGBoost	
B2	Parties fail to call before moving onto ROW	One-call system exists, pipeline hazard perception level is low, average public engagement level, dig notification required and enforced	0.5
B3	ROW indicators not recognized	Continuous but limited ROW indication, pipeline hazard perception level is low, average public engagement level	0.5
B4	Parties ignore ROW indicators	One-call system exists, pipeline hazard perception level is low, average public engagement level	0.35
B5	One-call system fails to notify relevant operator	Unified one-call system to minimum standards	0.005
B6	Explicit signage not seen	No explicit pipeline signage	1.0
B7	Parties ignore explicit signage	Pipeline hazard perception level is low, dig notification required and enforced	0.1
B8	Permanent above-ground markers fail to prompt notification	No permanent above-ground alignment markers	1.0
B9	No surveillance during activity period	Vital: Surveillance interval is weekly Non-Vital: Surveillance interval is annually or longer	0.83 1.0
B10	Surveillance fails to detect activity	Surveillance method is aerial patrol	0.01
B11	Activity depth causes interference	Depth of cover less than 4 metres	$1.13e^{-0.985\times DoC}$

B12a	Failure of buried measures in an authorized activity	No marker tape, no mechanical protection	1.0
B12u	Failure of buried measures in an unauthorized activity	No marker tape, no mechanical protection	1.0
B13	Permanent above-ground markers fail to convey location	No permanent above-ground alignment markers	1.0
B14	Pipeline is not located	Dig notification response time in more than three days	0.037
B15	Locating or marking error	Locating method by magnetic techniques	0.042
B16	Accidental interference in an authorized activity	Vital: Site supervision provided throughout the activity Non-Vital: Site supervision not available	0.088 0.352
C1	Unauthorized activity not reported by others	Assumed to be a constant value	0.97

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 4, Schedule 3

Preamble:

For the Wilson Ave. pipeline, page 16 of the evidence refers to the incremental O&M being recorded in the Asset Life Extension (ALE) deferral account for later recovery.

Question(s):

Please provide the criteria to be used for that account that would define appropriate allocations to it.

a) Please provide the accounting order for ALE deferral account.

Response:

The Asset Life Extension (ALE) Deferral Account allows Enbridge Gas to record incremental asset life extension O&M costs incurred as a result of activities undertaken in conjunction with findings from the Enhanced Distribution Integrity Management Program (EDIMP). Accordingly, following the deferral or elimination of capital work as a result of EDIMP activities, any incremental O&M costs are allocated to the ALE Deferral Account when they are directly attributable to maintaining the continued operation of the affected asset.

a) The accounting order for the ALE deferral account is provided at Attachment 1.

ENBRIDGE GAS INC.

Accounting Entries for
Asset Life Extension (ALE) Costs Deferral Account
Account No. 179-343

This account records incremental asset life extension O&M costs which are incurred as a result of activities taken in conjunction with findings from the EDIMP program. There is no materiality threshold associated with this new deferral account.

At the time that Enbridge Gas seeks clearance of amounts recorded in the new Asset Life Extension Costs Deferral Account, Enbridge Gas will provide evidence about the cost associated with work or projects avoided, downsized or delayed because of the ALE work. This account is effective upon approval of the EB-2024-0111 Settlement Proposal.

Simple interest is to be calculated on the opening monthly balance of this account using the OEB-approved EB-2006-0117 interest rate methodology, as well as any updates to this methodology decided by the OEB in its EB-2024-0063 generic proceeding on cost of capital and other matters. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the OEB in a future rate application.

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act, 1998.

Debit	-	Account No. 179-343 Asset Life Extension (ALE) Costs Deferral Account
Credit	-	Account No. 728 General Expense

To record, as a debit in the account, the incremental asset life extension operating costs incurred as a result of activities taken in conjunction with findings from the EDIMP program.

Debit	-	Account No.179-343 Asset Life Extension (ALE) Costs Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in the account, interest expense on the opening monthly balance.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, Page 6

Preamble:

GI evidence states: Peaking services often have low fixed demand costs, however, they can be extremely expensive in the event supply is called upon since their commodity costs are often tied to the price at market locations that trade at a significant premium to Dawn. Enbridge Gas prefers to limit peaking services to a maximum limit of 2% of design day demand for each delivery area.

We would like to understand better the cost and utilization of peaking services.

Question(s):

For each of the last 5 years, for each of the Enbridge CDA, Enbridge EDA and Union EDA, please provide:

a) The amount of daily demand contracted for through peaking services
    i. How many days of call contracted for each winter
    ii. The demand charge for each winter contracted
b) For each winter, please provide the days that EGI actually called for the supply
    i. The commodity price that was paid for those days
c) For those specific days that EGI called on the peaking service, please provide:
    i. A list of exchange or optimizations provided to third parties for deliveries to the specific delivery areas
    ii. The revenue generated by each of those transactions

Response:

a-c) Please see Table 1 for the daily peaking service volumes contracted, the number of days of call contracted, and the total annual demand charges paid for each of the services contracted for each of the Enbridge CDA, Enbridge EDA and Union EDA for the 2021/22 through 2025/26 gas years. No peaking service supply was called upon in any of the last five gas years.

Table 1
Annual Peaking Services Detail – Gas Years 2021/22 to 2025/26

Line No.	Particulars	Enbridge CDA	Enbridge EDA	Union EDA
	2025/26			
1	Volume Contracted (GJ/d)	132,456	21,953	8,916
2	# of Days of Call Contracted	10	10	10
3	Demand Charges ($CAD)	68,675	31,211	21,043
	2024/25			
4	Volume Contracted (GJ/d)	97,289	14,311	1,906
5	# of Days of Call Contracted	10	10	10
6	Demand Charges ($CAD)	-	27,128	4,500
	2023/24			
7	Volume Contracted (GJ/d)	63,260	13,833	16,982
8	# of Days of Call Contracted	10	10	10
9	Demand Charges ($CAD)	-	40,536	49,765
	2022/23			
10	Volume Contracted (GJ/d)	47,633	785	3,505
11	# of Days of Call Contracted	10	10	10
12	Demand Charges ($CAD)	-	2,306	10,298
	2021/22			
13	Volume Contracted (GJ/d)	22,000	485	3,100
14	# of Days of Call Contracted	10	10	10
15	Demand Charges ($CAD)	19,424	1,150	7,345

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, Page 6

Preamble:

EGI evidence states: On an actual basis, load balancing requirements may be higher/lower than planned due to customer demand being above/below normal. Enbridge Gas manages unplanned load balancing requirements for all bundled in-franchise customers in the EGD rate zone. 13.
As provided in Table 1, 2025 planned Dawn supply purchases for the EGD rate zone were 38.9 PJ,13 whereas actual Dawn supply purchases were 61.4 PJ.14

Question(s):

In an Excel spreadsheet, for each of the EGD CDA and EDA, please provide:

a) the forecasted monthly Heat Degree Days (HDD)

b) the forecasted monthly consumption for each of system gas and Direct purchase

c) the forecasted monthly Dawn price

d) the actual monthly heating degree days

e) the actual monthly consumption for each of system gas and Direct purchase

f) the actual monthly Dawn price

Response:

a) Please see response at Exhibit I.FRPO-2, Attachment 2, Table 8 for the 2025 forecasted monthly Heating Degree Days (HDD). Enbridge CDA considers the Central weather zone and West weather zone, and Enbridge EDA considers the East weather zone.

b) Please see Attachment 1, Table 1 for Monthly Forecast Consumption for sales service and direct purchase customers in the Enbridge CDA and Enbridge EDA.

c) Please see Attachment 1, Table 2 for forecasted monthly Dawn prices.

d) Please see Exhibit I.FRPO-2, Attachment 2, Table 7 for the 2025 actual monthly Heating Degree Days (HDD). Enbridge CDA considers the Central weather zone and West weather zone, and Enbridge EDA considers the East weather zone.

e) Please see Attachment 1, Table 3 for actual monthly consumption for sales service and direct purchase customers in the Enbridge CDA and Enbridge EDA.

f) Please see Attachment 1, Table 4 for actual monthly Dawn prices.

Table 1
2025 Monthly Forecast Consumption (TJ)

Line No.	Delivery Area	Customer Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Enbridge CDA	Sales Service	47,614	43,536	37,447	24,317	11,433	6,735	5,896	6,006	6,933	13,646	26,968	39,309
2		Direct Purchase	16,909	16,331	14,701	11,635	8,611	6,883	6,552	6,224	6,225	8,246	11,863	15,054
3	Enbridge EDA	Sales Service	9,116	8,300	7,119	4,349	1,676	1,051	903	956	1,116	2,557	5,147	7,599
4		Direct Purchase	2,474	2,533	2,173	1,541	1,040	779	762	659	786	1,095	1,559	2,341

Table 2
2025 Forecasted Dawn (Ontario Delivered) Price

Line No.	Particulars (CAD $/103m3)	2025 Forecast Dawn Price (1)
1	Jan	$148.486
2	Feb	$145.180
3	Mar	$138.488
4	Apr	$187.526
5	May	$182.785
6	Jun	$183.619
7	Jul	$163.940
8	Aug	$167.132
9	Sep	$161.410
10	Oct	$134.634
11	Nov	$160.848
12	Dec	$187.035

Notes:

(1) Exhibit G, Tab 5, Schedule 1, Page 15, Col. (f).
(2) Forecasted average prices = Forecasted supplies costs / Forecasted supplies volumes. Refer to the monthly pricing information in the QRAM evidence, Exhibit C, Tab 1, Schedule 4, Col. (e). Jan to Mar prices come from Jan 2025 QRAM (EB-2024-0326), Apr to Jun prices come from Apr 2025 QRAM (EB-2025-0078), Jul to Sep prices come from Jul 2025 QRAM (EB-2025-0165) and Oct to Dec prices come from Oct 2025 QRAM (EB-2025-0244).

Table 3
2025 Actual Monthly Consumption (TJ)

Line No.	Delivery Area	Customer Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Enbridge CDA	Sales Service	52,392	43,431	34,488	23,353	12,967	5,236	7,171	6,505	7,315	11,972	30,193	45,674
2		Direct Purchase	25,021	26,090	18,385	15,860	11,146	8,832	12,937	12,253	11,712	15,231	18,866	23,995
3	Enbridge EDA	Sales Service	9,420	8,398	6,275	3,980	1,885	999	1,138	1,108	1,158	2,276	5,721	9,194
4		Direct Purchase	2,661	2,705	2,048	1,738	1,153	877	829	842	960	1,242	1,951	2,694

Table 4

2025 Actual Dawn (Ontario Delivered) Price

Line No.	Particulars (CAD $/10^{3}m^3)	2025 Dawn Price (1)
1	Jan	$175.427
2	Feb	$202.507
3	Mar (2)	$206.421
4	Apr (2)	$188.678
5	May (2)	$148.113
6	Jun (2)	$139.633
7	Jul	$137.748
8	Aug (2)	$140.532
9	Sep (2)	$131.817
10	Oct	$156.766
11	Nov (2)	$163.042
12	Dec	$231.285

Notes:

(1) Exhibit G, Tab 5, Schedule 1, p. 15, Col. (g)

(2) Dawn IF Monthly Index Prices are used for months that have no actual Dawn purchases.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, Page 6

Preamble:

EGI evidence states: On an actual basis, load balancing requirements may be higher/lower than planned due to customer demand being above/below normal. Enbridge Gas manages unplanned load balancing requirements for all bundled in-franchise customers in the EGD rate zone. 13.

As provided in Table 1, 2025 planned Dawn supply purchases for the EGD rate zone were 38.9 PJ,13 whereas actual Dawn supply purchases were 61.4 PJ.14

Question(s):

For purchases made during the winter months of December to February, please provide a table showing the prices that would have been available if EGI had contracted for deliveries of gas for each of these months at Dawn 3,6, 9, and 12 months prior to November 1st (i.e., For 2025 months of January and February, the price of gas available at Dawn for those months as of Nov. 1/23, Feb. 1/24, May 1/24 and Aug. 1/24).

Response:

Please see Table 1 for the historical forward Dawn gas supply prices for January and February 2025, as of the trading dates requested.

Table 1
Historical Forward Dawn Prices ($US/MMBtu)

Line No.	Trade Date	Dec-24	Jan-25	Feb-25
1	1-Nov-23	4.088	4.284	4.238
2	1-Feb-24	3.261	3.438	3.339
3	1-May-24	3.239	3.415	3.383
4	1-Aug-24	2.694	2.958	3.071

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, Page 7

Preamble:

EGI evidence states: The total cost associated with the Dawn supply purchases of 61.4 PJ was $310.2 million.

Question(s):

Please clarify how the "total cost" in the above preamble was determined.

a) To the extent that it is different, please provide the unit cost of gas at:
   i) WACOG
   ii) Dawn reference price from QRAM.

Response:

a) The total cost of Dawn supply purchases for the EGD rate zone of $310.2 million represents the actual cost of gas supply procured at Dawn. Table 1 provides the monthly WACOG and the corresponding QRAM-approved reference prices for both the EGD and Union rate zones.

Table 1
2025 EGD Rate Zone Dawn Supply Purchases

Line No.	Particulars	Supply Cost ($million)	Volume (TJ)	WACOG ($/GJ)	EGD Reference Price ($/GJ) (1)	Union Dawn Reference Price ($/GJ) (1)
		(a)	(b)	(c) = (a) / (b)	(d)	(e)
1	January	$97.3	21,700	$4.483	$4.269	$3.754
2	February	$87.8	16,968	$5.175	$4.269	$3.754
3	March	$0.0	0	-	$4.269	$3.754
4	April	$0.0	0	-	$5.403	$5.112
5	May	$0.0	0	-	$5.403	$5.112
6	June	$0.0	0	-	$5.403	$5.112
7	July	$7.0	2,061	$3.396	$5.337	$4.842
8	August	$0.0	0	-	$5.337	$4.842
9	September	$0.0	0	-	$5.337	$4.842
10	October	$8.4	2,113	$3.956	$4.928	$4.418
11	November	$0.0	0	-	$4.928	$4.418
12	December	$109.8	18,569	$5.913	$4.928	$4.418
13	Total	$310.2	61,411			

Notes:
(1) Jan 2025 QRAM: EB-2024-0326
Apr 2025 QRAM: EB-2025-0078
Jul 2025 QRAM: EB-2025-0165
Oct 2025 QRAM: EB-2025-0244

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, Page 8

Preamble:

EGI evidence states: Enbridge Gas did not make a base rate adjustment for the 2024 gas supply plan and any variances in gas costs have been recovered in gas supply deferral and variance accounts.

Question(s):

For each month of 2025, in a table, please describer and quantify the variances that have been recovered while referencing the specific evidence in QRAM or other evidence.

Response:

The purchase price variance recorded in the Purchased Gas Variance Account (PGVA) account reflects the difference between the actual cost of gas purchased and the forecast gas supply costs embedded in rates, applied to the actual purchase volumes. The gas supply plan used to establish rates for the EGD rate zone is based on the gas supply planning methodology approved in the 2019 Rates Application[1].

Attachment 1 provides a monthly breakdown of the 2025 PGVA balance for the EGD rate zone, segregated into commodity, transportation, and load balancing components. The commodity cost variance, presented in column (g) of the table, reflects the variance between actual and forecast commodity purchase costs incurred to serve EGD sales service customers. Commodity-related variances are allocated to sales service customers.

The transportation variance recorded in the PGVA account, as presented in column (h) of Table 1, reflects the difference between actual upstream transportation costs and the forecast upstream transportation costs embedded in rates. Transportation-related

[1] EB-2018-0305.

variances are allocated to sales service, Dawn T-Service, and Western T-Service customers.

The load balancing variance reflects the difference between the forecast and actual price differential associated with Empress and Dawn supply, applied to actual monthly Dawn supply purchase volumes. In addition, variances arising from differences between forecast and actual peak service costs and load balancing fees are recorded within this component. The actual monthly load balancing variances for 2025 are presented in column (i) of Attachment 1. Load balancing cost variances are recovered from both sales and direct purchase customers.

Table 1

Summary of the 2025 Monthly Gas Supply Variance - EGD Rate Zone

Line No.	Particulars	Actual Purchase Cost ($000s) (1)	Actual Supplies (10^3m^3) (2)	Actual Weighted Average Cost of Gas ($/$10^3m^3$)	QRAM Approved Ref. Prices (3) ($/$10^3m^3$)	Price Variance ($/$10^3m^3$)	Purchase Price Variance (4) ($000s)	Commodity Cost Variance (5) ($000s)	Transportation Cost Variance (6) ($000s)	Total Load Balancing & Peaking Costs Variance (7) ($000s)	Monthly Variance (8) ($000s)
		(a)	(b)	(c)=(a)/(b)	(d)	(e) = (c)-(d)	(f) = (b)*(e)	(g)	(h)	(i)	(j) = (g)+(h)+(i)
1	Jan	219,160.9	1,200,578.2	182.546	166.822	15.724	$18,877.9	$8,932.0	$3,998.9	$5,947.0	$18,877.9
2	Feb	195,739.1	1,017,150.5	192.439	166.822	25.617	$26,056.0	$2,388.3	$3,103.2	$20,564.6	$26,056.0
3	Mar	131,321.9	646,869.5	203.011	166.822	36.189	$23,409.9	$20,185.7	$3,461.6	($237.5)	$23,409.9
4	Apr	82,797.9	477,789.5	173.294	211.145	(37.851)	($18,085.0)	($19,229.1)	$857.1	$286.9	($18,085.0)
5	May	86,857.8	550,092.3	157.897	211.145	(53.248)	($29,291.4)	($29,683.7)	$605.3	($213.0)	($29,291.4)
6	Jun	81,396.4	531,356.7	153.186	211.145	(57.959)	($30,796.9)	($31,534.1)	$678.8	$58.4	($30,796.9)
7	Jul	88,374.2	605,032.3	146.065	208.564	(62.499)	($37,813.8)	($38,391.9)	$708.2	($130.1)	($37,813.8)
8	Aug	74,999.0	552,481.6	135.749	208.564	(72.815)	($40,228.7)	($40,744.5)	$559.6	($43.8)	($40,228.7)
9	Sep	60,100.4	444,180.6	135.306	208.564	(73.258)	($32,539.7)	($33,099.7)	$534.9	$25.0	($32,539.8)
10	Oct	73,130.8	535,164.4	136.651	192.574	(55.923)	($29,927.9)	($31,980.4)	$627.5	$1,425.0	($29,927.9)
11	Nov	95,513.7	529,161.4	180.500	192.574	(12.074)	($6,389.1)	($7,218.0)	$809.8	$19.2	($6,389.0)
12	Dec	255,610.5	1,115,434.5	229.158	192.574	36.584	$40,806.9	$24,869.9	$3,495.1	$12,441.8	$40,806.8
		1,445,002.6	8,205,291.5				($115,921.9)	($175,505.3)	$19,439.9	$40,143.5	($115,921.9)

Notes:

(1) Refer to the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, Page 1, Col. 1.
Jan to Oct: Jan 2026 QRAM (EB-2025-0308), Nov to Dec: Apr 2026 QRAM (EB-2026-0091)

(2) Refer to the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, Page 1, Col. 2.
Jan to Oct: Jan 2026 QRAM (EB-2025-0308), Nov to Dec: Apr 2026 QRAM (EB-2026-0091)

(3) Jan to Mar: Jan 2025 QRAM (EB-2024-0326)
Apr to Jun: Apr 2025 QRAM (EB-2025-0078)
Jul to Sep: Jun 2025 QRAM (EB-2025-0165)
Oct to Dec: Oct 2025 QRAM (EB-2025-0244)

(4) Refer to the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, Page 1, Col. 6.
Jan to Oct: Jan 2026 QRAM (EB-2025-0308), Nov to Dec: Apr 2026 QRAM (EB-2026-0091)

(5) Detailed breakdown of the various monthly supplies for commodity cost variances can be found in the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, Pages 3 and 4, Col. 4.
Jan to Oct: Jan 2026 QRAM (EB-2025-0308), Nov to Dec: Apr 2026 QRAM (EB-2026-0091)

(6) Detailed breakdown of the transportation cost variances can be found in the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, Pages 3 and 4, Col. 5.
Jan to Oct: Jan 2026 QRAM (EB-2025-0308), Nov to Dec: Apr 2026 QRAM (EB-2026-0091)

(7) Detailed load balancing cost variance calculations can be found in Exhibit G, Tab 5, Schedule 1, Appendix 3, Col. P.

(8) Sum of commodity cost variance, transportation cost variance and load balancing cost variance equal to the purchase price variance in column (f).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, Pages 9-15
EB-2025-0155 Exhibit I.FRPO-22 and
EB-2017-0086, Exhibit G2, Tab 6, Sch. 2, p.1 and Exhibit G2, Tab 1, Sch. 1

Preamble:

In the first reference, EGI evidence states: Forecast commodity purchase costs updated with the QRAM are used to derive gas supply charges each quarter based on the approved forecast volumes underpinning 2025 rates. Forecast commodity purchase costs include Dawn supply volumes of 2,649,848 103m3 (102.1 PJ) and peaking supply volumes of 6,902 103m3 (0.3 PJ) based on the gas supply plan in base rates.19

For 2025, forecast Dawn supply purchase costs were classified between system commodity costs, transportation, and load balancing costs (split between peaking and seasonal).

In the second reference, EGI's reply to our questions in this area stated: Under the current approved cost allocation study underpinning rates for the EGD rate zone, any price premium for gas supply purchased at other supply hubs over the Empress reference price is classified as transportation (i.e. deemed transportation costs) and, in the case of delivered supplies, also to load balancing as peaking and seasonal. In this classification, 71% is attributed as seasonal load balancing and 9% peak load balancing. The remaining 20% is deemed transportation.

The relevant cost model schedules (the classification of gas costs to commodity, annual transportation and load balancing charges) and the related written evidence can be found in the 2018 rates application.[4]

4 EB-2017-0086, Exhibit G2, Tab 6, Sch. 2, p.1 and Exhibit G2, Tab 1, Sch. 1

In spite of these footnoted general references from the 2018 EGD rate setting, we are still trying to understand better, the allocation principles and their appropriateness to enhanced use of landed gas at Dawn as a substitute for storage.

Question(s):

From the first reference, please confirm that the classification between system commodity costs, transportation and load balancing is allocated using the same methodology as 2024.

a) If not, please explain any variances in methodology.
    i. If so, please provide an explanatory description of the footnoted references that clearly describes the methodology with reference to the original adoption of the approach (prior to the QRAM Generic Proceeding) that was approved by the Board including appropriate evidence that the Board relied upon.
b) Does the price premium over the Empress price apply to delivered supplies?
    i. If so, does the further 20% deemed transportation also apply?
    ii. If not, why not?
c) Please explain the source reference and the appropriateness of each of the classification figures of 71%, 9% and 20%.
d) For each month, in an Excel table, please provide the actual deliveries that applied the price premium and, assuming that they are distinct, all deliveries that applied the 20% to transportation.
    i. Please layout the table showing the volumes, the price applied, the transportation allocation and the unit transportation cost applied for each month for each type of delivery.

Response:

a) Confirmed.

The OEB approved the QRAM methodology to recover commodity, load balancing and transportation costs from EGD rate zone customers in the 2005 rate case[1]. The classification of gas purchases between commodity, transportation, seasonal and peak. was presented in the cost allocation study approved in the proceeding.

The methodology was reviewed further and approved annually up to and including the 2018 rate case[2].

[1] RP-2023-0203.
[2] EB-2017-0086.

Aside from the rate case proceedings, the OEB and interested parties conducted an in-depth review as part of the QRAM Generic Proceeding[3], the QRAM Process Review[4] and also more recently as part of the stakeholder consultation on Ontario Landed Reference Price for Gas Supply[5].

The evidence presented in Exhibit G, Tab 5, Schedule 1, pages 9 to 15 is underpinned by the gas cost model filed for the 2018 rate case[6]. The relevant cost model schedules (the classification of gas costs to commodity, annual transportation and load balancing charges) and the related written evidence can be found in the 2018 rate case at Attachment 3[7] and Attachment 4[8] respectively.

b) The Empress reference price, inclusive of fuel, is used to design/set the gas supply charge. Any price premium or discount for gas supplies purchased at other supply hubs over the Empress reference price are classified as transportation. Only in the case of delivered supplies (i.e. Dawn purchases) are costs classified to transportation and load balancing as peaking and seasonal.

c) As described in part a), the classification of delivered supplies as commodity, transportation and load balancing peaking and seasonal is underpinned by the gas cost models presented in 2018 Rates.

Prior to 2019, the EGD rate zone updated the gas supply plan in rates as part of the annual rate setting process. The January 2019 QRAM[9] and 2019 Rates[10] applications were filed based on the 2019 Gas Supply Plan[11], in accordance with the established practice for the EGD rate zone. Subsequent to the approval of the April 2019 QRAM[12], the OEB issued Procedural Order 2 as part of the 2019 Rates proceeding which determined that Gas Supply Plan issues were out of scope for the application. As a result of the decision in Procedural Order 2, the percentages used to allocate costs between transportation and load balancing peak and seasonal should have reverted back to the cost models approved in 2018 Rates. However, the Company has determined that the QRAM applications subsequent to the issuance of Procedural Order 2 continued to apply allocations to load balancing based allocations underpinned by the 2019 Gas Supply Plan.

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[3] EB-2008-0106.
[4] EB-2014-0199.
[5] EB-2017-0086, Exhibit H1, Tab 2, Schedule 2, Appendix 1.
[6] EB-2017-0086.
[7] EB-2017-0086, Exhibit G2, Tab 6, Schedule 2, p.1.
[8] EB-2017 0086, Exhibit G2, Tab 1, Schedule 1.
[9] EB-2018-0313.
[10] EB-2018-0305.
[11] EB-2019-0137.
[12] EB-2019-0095.

Enbridge Gas affirms that this oversight does not have an impact on the process and methodology for the classification of costs to transportation and load balancing as part of the QRAM process. This oversight is a result of changes in the approach of including annual gas supply plan updates in the QRAM and annual rate processes for the EGD rate zone. Enbridge Gas notes that the impact to the October 1, 2026 QRAM of adjusting the delivered supplies allocations to peak, seasonal and annual transportation based on 2018 Rates would have had an immaterial impact to rate classes as shown in Table 1.

Table 1
Summary Impact of Delivered Supplies Adjustment

Line No.	Particulars ($millions)	Pipeline – Peak Load Balancing	Pipeline - Seasonal Load Balancing	Pipeline - Annual Transportation	Total
		(a)	(b)	(c)	(d)
1	Rate 1	0.6	4.6	(5.8)	(0.6)
2	Rate 6	0.5	4.2	(4.2)	0.5
3	Rate 100	0.0	0.0	0.0	0.0
4	Rate 110	0.0	0.2	(0.2)	(0.0)
5	Rate 115	0.0	0.0	0.0	0.0
6	Rate 125	0.0	0.0	0.0	0.0
7	Rate 135	0.0	0.0	(0.0)	(0.0)
8	Rate 145	0.0	0.0	(0.0)	0.0
9	Rate 170	0.0	0.1	(0.0)	0.0
10	Rate 200	0.0	0.1	(0.2)	0.0
11	Total	1.2	9.2	(10.4)	0.0

The impact is a shift of costs from transportation (decrease) to load balancing (increase). The adjustment does not impact the total forecast amount to be recovered in rates, however it does impact how the costs are recovered by rate type. All customers are impacted by the change to load balancing rates whereas only sales service and Western Transportation Service (WTS) are impacted by the change to transportation. For a typical residential sales service customer, the impact of this change would be an annual bill decrease of approximately $0.34 or 0.0%. Based on the immaterial nature of the correction, the Company intends to correct the allocation to peak, seasonal and annual to align with Gas Cost to Operations schedule as approved in 2018 Rates[13] on a prospective basis effective January 1, 2027 QRAM.

[13] EB-2017-0086, Exhibit G2, Tab 6, Schedule 2, p.1.

The correct allocation factors based on 2018 Rates are 9.5% to peak, 76.2% seasonal and 14.3% to annual. The evidentiary reference for these allocations is found at EB-2017-0086, Exhibit G2, Tab 6, Schedule 2, page 1. Please see Table 2 for the derivation of the allocations:

Table 2
Derivation of Allocation Percentages

Line No.	Particulars ($ millions)	Amount (a)	% (b)
1	Total Delivered Supplies (1)	424,684.1	
2	Less: Variable Cost (2)	309,016.5	
3	Total to be Allocated for Load Balancing	115,667.6	
4	Peak (3)	11,011.4	9.5%
5	Seasonal (4)	88,091.4	76.2%
6	Annual (5)	16,564.7	14.3%
7	Total Allocated	115,667.6	100.0%

Notes:
(1) EB-2017-0086 Exhibit G2, Tab 6, Schedule 2, p.1, line 1.7, col. 11
(2) EB-2017-0086 Exhibit G2, Tab 6, Schedule 2, p. 1, line 1.7, col. 3
(3) EB-2017-0086 Exhibit G2, Tab 6, Schedule 2, p. 1, line 1.7, col. 7 divided by Line 7, Total Allocated
(4) EB-2017-0086 Exhibit G2, Tab 6, Schedule 2, p. 1, line 1.7, col. 8 divided by Line 7, Total Allocated
(5) EB-2017-0086 Exhibit G2, Tab 6, Schedule 2, p. 1, line 1.7, col. 9 divided by Line 7, Total Allocated

Enbridge Gas notes that the Phase 3 2024 Rebasing Settlement Agreement[14] approved a rate harmonization plan which includes changes to the rate design methodologies for the determination and recovery of storage and load balancing costs. The Company expects to implement harmonized rates in 2028.

d) Please response at Exhibit I.FRPO-35 parts b) and c).

[14] EB-2025-0064, Decision on Settlement Proposal and Rate Order, March 26, 2026.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, Pages 9-15
EB-2025-0155 Exhibit I.FRPO-22 and
EB-2017-0086, Exhibit G2, Tab 6, Sch. 2, p.1 and Exhibit G2, Tab 1, Sch. 1

Preamble:

In the first reference, EGI evidence states: Forecast commodity purchase costs updated with the QRAM are used to derive gas supply charges each quarter based on the approved forecast volumes underpinning 2025 rates. Forecast commodity purchase costs include Dawn supply volumes of 2,649,848 103m3 (102.1 PJ) and peaking supply volumes of 6,902 103m3 (0.3 PJ) based on the gas supply plan in base rates.19

For 2025, forecast Dawn supply purchase costs were classified between system commodity costs, transportation, and load balancing costs (split between peaking and seasonal).

In the second reference, EGI's reply to our questions in this area stated: Under the current approved cost allocation study underpinning rates for the EGD rate zone, any price premium for gas supply purchased at other supply hubs over the Empress reference price is classified as transportation (i.e. deemed transportation costs) and, in the case of delivered supplies, also to load balancing as peaking and seasonal. In this classification, 71% is attributed as seasonal load balancing and 9% peak load balancing. The remaining 20% is deemed transportation.

The relevant cost model schedules (the classification of gas costs to commodity, annual transportation and load balancing charges) and the related written evidence can be found in the 2018 rates application.[4]

4 EB-2017-0086, Exhibit G2, Tab 6, Sch. 2, p.1 and Exhibit G2, Tab 1, Sch. 1

In spite of these footnoted general references from the 2018 EGD rate setting, we are still trying to understand better, the allocation principles and their appropriateness to enhanced use of landed gas at Dawn as a substitute for storage.

Question(s):

In the first reference, EGI provides that forecast commodity purchases use forecast volumes underpinning 2025 rates.

a) Please provide these monthly volumes and sourced reference for those volumes including the appropriate QRAM proceeding number.

b) Why are these volumes not shown in the derivation of Load Balancing Costs Variance in Appendix 3.

c) In Appendix 3, why are the prices used the monthly forecast price as opposed to the QRAM price for that month as was done in Table 2 in the primary evidentiary reference. Please explain fully.

Response:

a) Please see Attachment 1 for the monthly commodity purchase volumes underpinning the 2019 budget volumes approved in 2019 Rates application[1]. The source document was originally filed under EB-2018-0305, Exhibit E1, Tab 4, Schedule 6, filed December 14, 2018.

b) The calculation of the actual load balancing cost variance follows a simplified approach, as there is no approved methodology for the EGD rate zone to determine a classification split of actual Dawn and peaking supply purchases. As such, the load balancing cost variance presented in Appendix 3 is calculated using actual Dawn supply purchase volumes, as shown in column (a). The forecast volumes are not separately included in the derivation of the load balancing cost variance presented in Appendix 3.

c) The load balancing cost variance presented in Appendix 3 is calculated on a monthly basis and is intended to reflect the actual variance recorded in the Purchased Gas Variance Account (PGVA). Accordingly, monthly forecast price differentials were used to calculate the forecast load balancing costs for each month, reflecting seasonal variations in supply pricing and gas supply purchases throughout the year.

   Table 2 presents the total annual forecast load balancing costs underlying the rates charged to customers. As that table is intended to show the annual forecast costs recovered through rates, it is appropriate to use the forecast prices reflected in the applicable QRAM, which represent the forecast cost assumptions approved for rate-setting purposes.

[1] EB-2018-0305.

Enbridge Gas Inc.
EGD Rate Zone - 2019 Budget - Gas Supply & Demand Balance

Item #		Col. 1 January 10^3m^3	Col. 2 February 10^3m^3	Col. 3 March 10^3m^3	Col. 4 April 10^3m^3	Col. 5 May 10^3m^3	Col. 6 June 10^3m^3	Col. 7 July 10^3m^3	Col. 8 August 10^3m^3	Col. 9 September 10^3m^3	Col. 10 October 10^3m^3	Col. 11 November 10^3m^3	Col. 12 December 10^3m^3	Col. 13 Total 10^3m^3
		1,982,098.4	1,770,279.2	1,547,907.6	972,867.4	569,145.8	379,198.3	351,637.4	357,335.5	359,224.0	744,392.4	1,209,412.7	1,678,883.5	
1.	Total Demand	1,982,098.4	1,770,279.2	1,547,907.6	972,867.4	569,145.8	379,198.3	351,637.4	357,335.5	359,224.0	744,392.4	1,209,412.7	1,678,883.5	11,922,382.2
	Deliveries													
2.1	Western Canadian Supplies	176,991.3	159,863.1	176,991.3	171,281.9	176,991.3	171,281.9	176,991.3	176,991.3	171,281.9	176,991.3	171,281.9	176,991.3	2,083,929.3
2.2	Peaking/Seasonal	6,902.0	-	-	-	-	-	-	-	-	-	-	-	6,902.0
2.3	Ontario Production	-	-	-	-	-	-	-	-	-	-	-	-	0.0
2.4	Chicago Supplies	55,176.2	49,836.5	55,176.2	53,396.3	55,176.2	53,396.3	55,176.2	55,176.1	53,396.3	55,176.2	53,396.3	55,176.2	649,654.9
2.5	Delivered Supplies	539,950.6	433,635.1	63,664.8	-	157,230.2	152,157.6	157,230.2	157,230.2	182,979.2	109,008.1	173,787.0	522,974.9	2,649,847.9
2.6	Niagara Supplies	160,913.6	145,341.3	160,913.6	155,722.8	160,913.6	155,722.8	160,913.6	160,913.6	155,722.8	160,913.6	155,722.8	160,913.6	1,894,627.6
2.7	Link Supplies	-	-	-	-	-	-	-	-	-	-	-	-	0.0
2.8	Dominion Supplies	93,375.1	84,338.7	93,375.1	90,363.0	93,375.1	90,363.0	93,375.1	93,375.1	90,363.0	93,375.1	90,363.0	93,375.1	1,099,416.1
2.9	Direct Purchase Delivery	296,589.5	267,887.3	296,589.5	287,022.1	296,589.5	287,022.1	296,589.5	296,589.5	287,022.1	296,589.5	287,022.1	296,589.5	3,492,101.7
2.10	Storage (Injection)/Withdrawal	652,200.2	629,377.2	701,197.2	215,081.4	(371,129.9)	(530,745.3)	(588,638.3)	(582,940.2)	(581,541.2)	(147,661.2)	277,839.7	372,863.0	45,902.8
2.	Total Delivery	1,982,098.4	1,770,279.2	1,547,907.6	972,867.4	569,145.8	379,198.3	351,637.4	357,335.5	359,224.0	744,392.4	1,209,412.7	1,678,883.5	11,922,382.2

Total Demand includes both System Sales and T-Service Consumption

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, Pages 9-15
EB-2025-0155 Exhibit I.FRPO-22 and
EB-2017-0086, Exhibit G2, Tab 6, Sch. 2, p.1 and Exhibit G2, Tab 1, Sch. 1

Preamble:

In the first reference, EGI evidence states: Forecast commodity purchase costs updated with the QRAM are used to derive gas supply charges each quarter based on the approved forecast volumes underpinning 2025 rates. Forecast commodity purchase costs include Dawn supply volumes of 2,649,848 103m3 (102.1 PJ) and peaking supply volumes of 6,902 103m3 (0.3 PJ) based on the gas supply plan in base rates.19

For 2025, forecast Dawn supply purchase costs were classified between system commodity costs, transportation, and load balancing costs (split between peaking and seasonal).

In the second reference, EGI's reply to our questions in this area stated: Under the current approved cost allocation study underpinning rates for the EGD rate zone, any price premium for gas supply purchased at other supply hubs over the Empress reference price is classified as transportation (i.e. deemed transportation costs) and, in the case of delivered supplies, also to load balancing as peaking and seasonal. In this classification, 71% is attributed as seasonal load balancing and 9% peak load balancing. The remaining 20% is deemed transportation.

The relevant cost model schedules (the classification of gas costs to commodity, annual transportation and load balancing charges) and the related written evidence can be found in the 2018 rates application.[4]

4 EB-2017-0086, Exhibit G2, Tab 6, Sch. 2, p.1 and Exhibit G2, Tab 1, Sch. 1

In spite of these footnoted general references from the 2018 EGD rate setting, we are still trying to understand better, the allocation principles and their appropriateness to enhanced use of landed gas at Dawn as a substitute for storage.

Question(s):

Table 2 shows simple high-level determination of load balancing costs and we believe Appendix 3 shows the determination of load balancing variances that we trust support the deferral disposition proposal.

a) Using the figures in Table 2 as a starting point, please show in an Excel table and describe the determination of the quarterly load balancing costs while including all dispositions that flowed through the PGVA account during the respective proceedings that impact the 2025 annual dispositions.

    i. Please ensure all sources of data displayed is referenced to the evidentiary source.

Response:

a) As noted in the response to Exhibit I.FRPO-35, Table 2 presents the total annual forecasted load balancing costs embedded in rates and updated quarterly based on the forward 12-month gas price forecast used in each QRAM. While Table 2 provides the annual forecasted load balancing costs reflected in rates, it is not intended to show the monthly load balancing cost variances included in the forecasted Purchased Gas Variance Account (PGVA) balances for disposition in each QRAM proceeding.

   The load balancing cost variances included in the PGVA consist of actual and forecasted variances relating to periods preceding the effective date of a QRAM. As a result, there is a timing difference between when load balancing cost variances are incurred and when they are disposed of through the PGVA. For example, the actual 2025 load balancing cost variances shown in Appendix 3 were not fully cleared through the PGVA until the April 2026 QRAM.

   Attachment 1 provides a summary of the load balancing cost variances disposed of through the PGVA from the January 2025 QRAM through the April 2026 QRAM.

   Specifically:

   - January 2025 QRAM: The load balancing cost variance disposed of through the PGVA included the true-up of forecasted variances for August and September 2024, actual variances for October 2024, and forecasted variances for November and December 2024.
   - April 2025 QRAM: The load balancing cost variance disposed of through the PGVA included the true-up of forecasted variances for November and December 2024, actual variances for January 2025, and forecasted variances for February and March 2025.

- July 2025 QRAM: The load balancing cost variance disposed of through the PGVA included the true-up of forecasted variances for February and March 2025, actual variances for April 2025, and forecasted variances for May and June 2025.
- October 2025 QRAM: The load balancing cost variance disposed of through the PGVA included the true-up of forecasted variances for May and June 2025, actual variances for July 2025, and forecasted variances for August and September 2025.
- January 2026 QRAM: The load balancing cost variance disposed of through the PGVA included the true-up of forecasted variances for August and September 2025, actual variances for October 2025, and forecasted variances for November and December 2025.
- April 2026 QRAM: The load balancing cost variance disposed of through the PGVA included the true-up of forecasted variances for November and December 2025, actual variances for January 2026, and forecasted variances for February and March 2026.

Accordingly, the quarterly load balancing cost variances disposed of through the PGVA do not align directly with the annual forecasted load balancing costs presented in Table 2, as each QRAM disposition includes a combination of true-up, actual, and forecasted variances from different periods.

Breakdown of Load Balancing Costs Variance - EGD Rate Zone

Line No	Particulars ($000)	Jan 2025 QRAM (1)			Apr 2025 QRAM (2)			Jul 2025 QRAM (3)			Oct 2025 QRAM (4)			Jan 2026 QRAM (5)			Apr 2026 QRAM (6)		
		True-up of Forecasted Variance (7)	Actual/Forecast Variance (8)	Total Variance	True-up of Forecasted Variance (7)	Actual/Forecast Variance (8)	Total Variance (9)	True-up of Forecasted Variance (7)	Actual/Forecast Variance (8)	Total Variance (9)	True-up of Forecasted Variance (7)	Actual/Forecast Variance (8)	Total Variance (9)	True-up of Forecasted Variance (7)	Actual/Forecast Variance (8)	Total Variance (9)	True-up of Forecasted Variance (7)	Actual/Forecast Variance (8)	Total Variance (9)
		(a)	(b)	(c) = (a)+(b)	(d)	(e)	(f) = (d)+(e)	(g)	(h)	(i) = (j)+(k)	(j)	(k)	(l) = (j)+(k)	(m)	(n)	(o) = (m)+(n)	(p)	(q)	(r) = (p)+(q)
1	Aug-24	(264.2)		(264.2)															
2	Sep-24	201.7		201.7															
3	Oct-24		1,678.8	1,678.8															
4	Nov-24		2,284.6	2,284.6	(2,639.0)		(2,639.0)												
5	Dec-24		15,648.0	15,648.0	(84.6)		(84.6)												
6	Jan-25					6,233.9	6,233.9												
7	Feb-25					22,288.3	22,288.3	(1,437.4)		(1,437.4)									
8	Mar-25					3,261.1	3,261.1	(3,212.3)		(3,212.3)									
9	Apr-25								277.3	277.3									
10	May-25								(6,157.9)	(6,157.9)	5,944.9		5,944.9						
11	Jun-25								(4,929.3)	(4,929.3)	4,987.7		4,987.7						
12	Jul-25											(130.1)	(130.1)						
13	Aug-25											4,340.2	4,340.2	(4,384.0)		(4,384.0)			
14	Sep-25											2,999.4	2,999.4	(2,974.4)		(2,974.4)			
15	Oct-25														1,425.0	1,425.0			
16	Nov-25														1,123.5	1,123.5	(1,104.3)		(1,104.3)
17	Dec-25														11,399.0	11,399.0	1,334.9		1,334.9
18	Jan-26																	(9,207.8)	(9,207.8)
19	Feb-26																	17,323.7	17,323.7
20	Mar-26																	1,002.0	1,002.0
21	Total PGVA Amounts - Load Balancing Component (9	(62.5)	19,611.4	19,548.9	(2,723.6)	31,783.3	29,059.7	(4,649.7)	(10,809.9)	(15,459.6)	10,932.6	7,209.5	18,142.1	(7,358.4)	13,947.5	6,589.1	230.6	9,117.8	9,348.4
22	True-up of Over/Under Collection of Rider C Amounts - Load Balancing (10)			(14.7)			1,142.1			19.3			2,088.6			(110.6)			(4,874.9)
23	Total disposition amounts for the derivation of Rider C unit rate (11)			19,534.2			30,201.8			(15,440.3)			20,230.7			6,478.5			4,473.6

Note
(1) EB-2024-0326.
(2) EB-2025-0078.
(3) EB-2025-0165.
(4) EB-2025-0244.
(5) EB-2025-0308.
(6) EB-2026-0091.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit G, Tab 5, Schedule 1, Pages 9-15
EB-2025-0155 Exhibit I.FRPO-22 and
EB-2017-0086, Exhibit G2, Tab 6, Sch. 2, p.1 and Exhibit G2, Tab 1, Sch. 1

Preamble:

In the first reference, EGI evidence states: Forecast commodity purchase costs updated with the QRAM are used to derive gas supply charges each quarter based on the approved forecast volumes underpinning 2025 rates. Forecast commodity purchase costs include Dawn supply volumes of 2,649,848 103m3 (102.1 PJ) and peaking supply volumes of 6,902 103m3 (0.3 PJ) based on the gas supply plan in base rates.19

For 2025, forecast Dawn supply purchase costs were classified between system commodity costs, transportation, and load balancing costs (split between peaking and seasonal).

In the second reference, EGI's reply to our questions in this area stated: Under the current approved cost allocation study underpinning rates for the EGD rate zone, any price premium for gas supply purchased at other supply hubs over the Empress reference price is classified as transportation (i.e. deemed transportation costs) and, in the case of delivered supplies, also to load balancing as peaking and seasonal. In this classification, 71% is attributed as seasonal load balancing and 9% peak load balancing. The remaining 20% is deemed transportation.

The relevant cost model schedules (the classification of gas costs to commodity, annual transportation and load balancing charges) and the related written evidence can be found in the 2018 rates application.[4]

4 EB-2017-0086, Exhibit G2, Tab 6, Sch. 2, p.1 and Exhibit G2, Tab 1, Sch. 1

In spite of these footnoted general references from the 2018 EGD rate setting, we are still trying to understand better, the allocation principles and their appropriateness to enhanced use of landed gas at Dawn as a substitute for storage.

Question(s):

In paragraph 25, EGI evidence states: Commodity variance costs are allocated to sales service customers only per the approved QRAM methodology.

a) Using the PGVA dispositions during 2025 cited in Table 2, please describe and show how commodity price differences in actual Empress pricing (varying from forecast) are captured in the load balancing accounts and allocated to direct purchase customers.

    i) If not allocated to direct purchase customers, please quantify the commodity price related variances for each month and describe where these costs are allocated.

Response:

The Empress reference price, inclusive of fuel, is applied to forecast Dawn and peaking supply purchase volumes to determine the portion of supply costs classified as system commodity supply costs. Consistent with the approved QRAM methodology, commodity cost variances arising from differences between forecast and actual Empress prices are allocated exclusively to system sales customers through the Purchased Gas Variance Account (PGVA).

The load balancing cost variance reflects the difference between the forecast and actual price differential between Empress and Dawn supply, applied to actual monthly Dawn supply purchase volumes. As shown in Exhibit G, Tab 5, Schedule 1, Appendix 3, the load balancing price variance of $40.6 million (column (j)) is derived from the price variance associated with the Ontario Delivered supply costs of $60.7 million (column (i)), offset by the commodity cost variance at Empress of $20.1 million.

The $20.1 million commodity cost variance represents the difference between forecast and actual Empress commodity prices applied to the applicable supply volumes. In accordance with the approved QRAM methodology, this variance is recorded in the PGVA and allocated to system sales customers only.

Accordingly, direct purchase customers are not allocated commodity price variances arising from differences between forecast and actual Empress prices. Direct purchase customers are allocated load balancing cost variances associated with the difference between forecast and actual price differentials associated with the Empress and Dawn supply.

    i) As commodity price variances associated with actual versus forecast Empress pricing are allocated exclusively to system sales customers through the PGVA, no portion of the $20.1 million commodity cost variance shown in Appendix 3 is allocated to direct purchase customers. The monthly

commodity cost variances attributable to differences between forecast and actual Empress prices that are allocated to system sales customers through the PGVA are listed in column (e) of Appendix 3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (OGVG)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 3, note (v); Exhibit B, Tab 3, Schedule 1, Table 1, line 18 and paragraph 8.

Preamble:

Enbridge Gas includes a $0.9 million “2025 DSMVA Correction” as an increase to utility O&M expenses in its 2025 earnings sharing calculation. The correction was recognized subsequent to the year-end corporate financial statements. The evidence also states that DSM expenditures above the OEB-approved budget are fully recoverable through the DSM variance account.

Question(s):

a) Explain the nature and cause of the $0.9 million correction, the period to which it relates, and why it is appropriately included in the 2025 ESM calculation.
b) Explain why including the correction does not reduce earnings sharing for an expense recoverable separately from ratepayers.
c) Provide the 2025 achieved ROE and ratepayer earnings sharing amount with and without the correction, including any associated tax or offsetting adjustments.

Response:

a) Subsequent to the completion of the 2025 year-end close process, Enbridge Gas identified an accrual that had been reflected in utility O&M expense that should instead have been recorded as a receivable from Natural Resources Canada (NRCan). Accordingly, the accrual reversed in January 2026 and a correcting entry was recorded in January 2026 to bring the expense account balance to zero regarding this error and credit the Demand Side Management Variance Account (DSMVA). The adjustment relates to 2025 activity and ensures that 2025 utility O&M expense and earnings are appropriately reflected as a pass through in earnings and the DSMVA reflects the true variance between the actual DSM spending for the fiscal year and the budgeted amount included within rates. Absent this correction,

2025 net earnings in relation to DSM would have been overstated and the DSMVA correspondingly understated.

b) The corresponding credit to the DSMVA increases the balance of amounts to be returned to ratepayers through the disposition of the 2025 DSMVA. As a result, the correction does not provide any additional benefit to Enbridge Gas and instead increases the amount ultimately refunded to customers.

   Excluding the correction from 2025 utility results would leave 2025 earnings overstated while the DSMVA would continue to reflect the increased amount owing to ratepayers. This would effectively result in the same amount being reflected both in higher utility earnings and in a larger refund to ratepayers. To ensure the appropriate matching of the utility earnings impact and the related DSMVA balance, the correction has been reflected in 2025 utility results. A corresponding adjustment will also be reflected in 2026 utility results to prevent duplication, as the correction has already been recognized in the 2025 ESM calculation.

c) Without the correction, Enbridge Gas's achieved ROE for 2025 would have been approximately 10.784%, compared to 10.774% as filed. After considering the associated tax effects, the earnings-sharing amount would have been approximately $0.5 million higher.

   However, excluding the correction from 2025 would not eliminate the earnings impact. Rather, it would defer the impact to 2026, resulting in a corresponding decrease to 2026 utility earnings and ROE. Recognizing the correction in 2025 therefore ensures that utility results are reported in the period to which the underlying activity relates and avoids a distortion of results between reporting periods.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Greenhouse Vegetable Growers (OGVG)

Interrogatory

Reference:

2025 QRAM filings, Exhibit E, Tab 2, Schedule 1, line 2; current application, Exhibit F, Tab 3, Schedule 2, page 1, line 2, and Schedule 3, page 2

Preamble:

It appears to OGVG that EGI is proposing to recover from M7 sales service customers a 2025 related debit related to optimization revenue that exceeds the optimization credit they received in the same year.

Question(s):

a) Please confirm that the optimization credit embedded in Union South sales-service rates throughout 2025 was 0.3006 cents/m³, and provide the total credit delivered to each rate class.

b) Please confirm that the amounts proposed for recovery through the Upstream Transportation Optimization Variance Account, Account 179-201, are:

Rate class	Proposed recovery
M1	$4,590,000
M2	$1,082,000
M4	$90,000
M5/M5A	$3,000
M7	$56,000
M9	$23,000

c) Please confirm that the proposed recovery is less than the 2025 credit provided for every class listed above except M7. If not, please explain and provide corrected figures.

d) Applying the credit to M7's reported 2025 sales-service volume of 11.458 million m³ produces a credit of approximately $34,443. Please explain why Enbridge Gas proposes to recover $56,000 from M7 customers, approximately $21,557 more than the credit provided, and provide a numerical reconciliation explaining why M7 differs from the other classes.

e) Please confirm the number of M7 customers that received the credit in 2025 and the number from which the proposed debit will be recovered, identifying any differences between those groups. Please provide the average and range of the proposed recovery per affected customer, in dollars and as a percentage of their annual gas bill

Response:

a) Confirmed. The gas supply optimization margin credit embedded in the Union South gas supply commodity rate for sales service customers throughout 2025 was 0.3006 cents/m^3.

In setting rates for 2024, the OEB approved a forecast of optimization revenue of $17.041 million. Of that amount, 90% or $15.337 million, was credited to ratepayers in the OEB-approved 2024 rates. Enbridge Gas notes that for the derivation of balances in the Upstream Transportation Optimization Variance Account, the credit of 0.3006 cents/m^3 applied to actual sales service volumes by rate class during the year does not determine the optimization credit included in current approved rates. The credit of 0.3006 cents/m^3 is based on the gas supply optimization credit for the Union South rate zone approved in the 2013 Cost of Service proceeding[1]. The rate was proportionally escalated to reflect the OEB approved 2024 Rebasing Phase 1 deficiency and the IRM adjustments from 2025 Rates.

In order to determine the amount assumed in rates based on the OEB approved forecast of $15.337 million, Enbridge Gas first determined the 2023 approved credit in rates based on 2024 board approved volumes. The calculated amount of $28.5 million exceeded the 2024 OEB approved amount of $15.337 million, therefore the balance of $28.5 million was proportionally reduced by $13.2 million to arrive at the amount assumed in rates, as provided in column (a) of Attachment 1.

b) Confirmed. Please see Attachment 1, column (e), lines 26 to 31.

[1] EB-2011-0210, Rate Order, Working Papers, Schedule 44, p.1, column (g).

c) Not confirmed. The Upstream Transportation Optimization Variance Account captures the variance between the ratepayers' 90% share of actual net revenues from optimization activities, and the amount refunded to ratepayers in rates. Please see the response to part a) for the optimization credit included in current approved rates.

d) Please see Attachment 1 for the calculation of the proposed 2025 deferral balance for disposition by rate class for the Upstream Transportation Optimization Variance Account (179-201). Column (a) provides the assumed Gas Supply Optimization credit included in rates by rate class. For Rate M7 in 2025, the assumed credit in rates is approximately $54,000 of the $15.337 million included in current approved rates. Column (b) provides the allocation of actual 2025 Gas Supply Optimization activity by rate zone during the year, allocated to rate classes in proportion to the actual sales service throughput volumes during the year. For Rate M7 in 2025, the allocation of actual optimization activity results in approximately $1,000 allocated to the rate class. The variance between these two amounts, plus interest, is the derivation of the Rate M7 deferral amount of approximately $56,000.

e) The number of Rate M7 Sales Service customers in 2025 that received the credit in 2025 includes 4 customers. The number of Rate M7 Sales Service customers in 2025 from which the proposed debit balance in the deferral account will be recovered from also includes 4 customers. The average proposed recovery of the debit balance by affected customers is approximately $14,000, ranging from $33 to $28,406. The average annual bill impact of the proposed recovery of the debit balance by affected customers is approximately 1.4%, ranging from 0.0% to 2.3%.

Derivation of 2025 Deferral Balances for Disposition in the
Upstream Transportation Optimization Variance Account (179-201)

Line No.	Particulars	2024 Assumed Optimization Credit in Rates ($000's)	Allocation of 2025 Actual Optimization ($000's)	Principal Balance ($000's)	Interest ($000's)	Balance for Disposition (2) ($000's)
		(a)	(b)	(c) = (a-b)	(d)	(e) = (c+d)
	EGD Rate Zone					
1	Rate 1	3,028	21,021	(21,831)	(1,182)	(23,013)
2	Rate 6	2,806	19,481	(13,698)	(742)	(14,439)
3	Rate 100	-	-	(62)	(3)	(66)
4	Rate 110	248	1,725	(645)	(35)	(680)
5	Rate 115	-	-	(0)	(0)	(0)
6	Rate 125	-	-	-	-	-
7	Rate 135	18	126	(7)	(0)	(7)
8	Rate 145	17	120	(2)	(0)	(2)
9	Rate 170	-	-	-	-	-
10	Rate 200	86	599	(622)	(34)	(656)
11	Rate 300	-	-	-	-	-
12	Rate 315	-	-	-	-	-
13	Total EGD Rate Zone	6,204	43,071	(36,867)	(1,996)	(38,863)
	Union North Rate Zone In-franchise - NW					
14	Rate 01	625	8	616	33	650
15	Rate 10	160	2	158	9	167
16	Rate 20	66	1	66	4	69
17	Rate 25	7	0	7	0	8
18	Rate 100	-	-	-	-	-
19	Total Union North Rate Zone In-franchise	859	12	848	46	894
	Union North Rate Zone In-franchise - NE					
20	Rate 01	1,597	4,484	(2,887)	(156)	(3,043)
21	Rate 10	549	1,542	(993)	(54)	(1,047)
22	Rate 20	231	648	(417)	(23)	(440)
23	Rate 25	1	2	(2)	(0)	(2)
24	Rate 100	-	-	-	-	-
25	Total Union North Rate Zone In-franchise	2,378	6,676	(4,299)	(233)	(4,532)
	Union South Rate Zone In-franchise					
26	Rate M1	4,643	288	4,354	236	4,590
27	Rate M2	1,082	55	1,026	56	1,082
28	Rate M4	90	5	85	5	90
29	Rate M5	3	0	3	0	3
30	Rate M7	54	1	53	3	56
31	Rate M9	24	2	22	1	23
32	Rate T1	-	-	-	-	-
33	Rate T2	-	-	-	-	-
34	Rate T3	-	-	-	-	-
35	Total Union South Rate Zone In-franchise	5,896	352	5,544	300	5,844
36	Total Union Rate Zones (line 18 + 25 + 35)	9,133	7,040	2,093	113	2,206
37	Total Enbridge Gas (line 13 + line 36)	15,337 (1)	50,112	(34,775)	(1,882)	(36,657)

Notes:
(1) EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023.
(2) EGD Rate Zone balances for disposition per Exhibit F, Tab 2, Schedule 2, line 1.
Union North Rate Zone balances for disposition per Exhibit F, Tab 3, Schedule 2, p. 2, line 2 and line 7.
Union South Rate Zone balances for disposition per Exhibit F, Tab 3, Schedule 2, p. 1, line 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Enbridge provides a list of eight 2025 accounts with no balance [C/2/24, page 1]

Question(s):

a) It appears that some of these account are at $0 for purposes of this application and for many accounts listed there would appear not be any future costs related to 2025. This would mean that there is no current balance that will ever need to be cleared. Please confirm this understanding or provide an explanation if not correct.

b) Does the list of accounts (those to be cleared and those with zero balance) represent the full list of all the deferral and variance accounts that exist for 2025. If not, what other existing accounts were not listed in this application.

Response:

a) Confirmed. The eight accounts listed on page 1, of Exhibit C, Tab 2, Schedule 24 have zero balances pertaining to the year ended 2025. Enbridge Gas does not expect there to be any future balance in these accounts to be cleared pertaining to the year ended 2025.

b) The accounts listed in Exhibit C, Tab 1, Schedule 1, page 1 of 1, and Exhibit C, Tab 2, Schedule 24, are not the full list of approved Enbridge Gas accounting orders. Consistent with past annual deferral and variance account clearance proceedings, Enbridge Gas Inc. has not listed accounts that will be reviewed through other processes in Exhibit C, Tab 1, Schedule 1, and these accounts are not addressed in this proceeding. Examples include gas supply accounts (i.e. PGVA) cleared through QRAM proceedings, and DSM related accounts.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

Please provide the balances for the following accounts and explain why they were not noted in this 2025 accounts application.

- IRP Capital Costs Deferral Account
- IRP Operating Cost Deferral Account

Response:

Please see Exhibit A, Tab 3, Schedule 1, Appendix A, page 1, Line No. 44 and 45 for the balance in the accounts and Exhibit C, Tab 2, Schedule 24, pages 6-8, for where they are explained in this application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

C/2/3 - UFGVA

Question(s):

a) Please explain why the variance between actual and forecasted UFG volumes was so large (i.e. almost three time more than forecast) resulted in a debit balance of $10.6 million in the UFGVVA, plus interest.

b) Does Enbridge know why the 2025 UFG is materially higher than the preceding years shown in the annual comparison table? If yes, please provide any materials available which provide the analysis and explanation.

Response:

a-b) To clarify, the variance between actual and forecast unaccounted for gas (UFG) volumes was not almost three times more than forecast. The 2025 OEB-approved volume is 243,682 10^3m^3 where actual 2025 UFG was 370,109 10^3m^3. Please see the response at Exhibit I. STAFF-1 part a) for 2025 UFG contributing sources.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

ACCOUNT NO. 179-302 DEFERRAL CLEARANCE VARIANCE ACCOUNT [C/2/5]

Question(s):

Please explain why the DSM and Federal Carbon Pricing Program accounts previously approved were not cleared in 2025, resulting in the residual clearance in this proceeding.

Response:

As noted in Exhibit C, Tab 2, Schedule 5, page 2, Enbridge Gas was approved to dispose of $55.830 million between the 2022 DSM and 2023 Federal Carbon account balances. Of that, $52.301 million was ultimately disposed of (recovered), resulting in the residual $3.529 million residual balance.

As noted in this exhibit:

> The residual balance reflects the outstanding amount resulting from the clearance of deferral and variance accounts which occurred during 2025 and the inability to locate and dispose of the approved amounts to all intended customers[1].

Further,

> Disposition variances result from Enbridge Gas's billing systems' inability to locate and apply deferral clearance unit rates to all intended customers and/or volumes. Due to customer moves and other account changes, deferral clearance unit rates derived utilizing historical customers and volumes are not able to be assessed against all historical customers and/or volumes at the time of disposition[2]…
>
> .

[1] Exhibit C, Tab 2, Schedule 5, p.2.
[2] Exhibit C, Tab 2, Schedule 5, p.1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

Did any of the DIMP/EDIMP related work in 2025 lead to any Asset Life Extension opportunities for capital assets in 2025. If not, why not.

Response:

The Distribution Integrity Management Program (DIMP)/Enhanced Distribution Integrity Management Program (EDIMP) related work completed in 2025 did not lead to any Asset Life Extension (ALE) opportunities for capital assets in 2025. ALE opportunities are typically identified after inspection results have been assessed and incorporated into a quantitative risk assessment (QRA) rather than in the same year that inspection activities are completed.

As described in Exhibit G, Tab 4, Schedule 1, page 12, each pipeline inspected through the 2025 EDIMP program will undergo a QRA in 2026, with long-term mitigation activities beginning as early as 2027. Any ALE opportunities identified through this process would begin to be reported in the 2026 DIMP and EDIMP Report on Activities, if applicable.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

In terms of detailing out the budget, the 2024 DIMP and EDIMP workplan originally submitted as part of the EB-2025-0155 proceeding is not the most current or accurate comparator as it does not properly reflect the bucketing of costs as defined by Enbridge Gas throughout this evidence (i.e., administrative costs include all Internal Integrity Resource costs, inclusive of those supporting project/program execution and those supporting project/program oversight and administration). [C/2/14]

Question(s):

a) Please provide the list of 2025 activities and related costs included in DIMP and EDIMP that were previously (prior to 2024) included in other program areas and are now part of DIMP/EDIMP.

b) Please provide the Enbridge manual or guidance wording (including the document source) for the methodology used by Enbridge staff to determine which integrity, administrative and overhead costs to allocate under the DIMP/EDIMP programs.

Response:

a) All Distribution Integrity Management Program (DIMP) Admin and Project costs were part of the overall Integrity Management Program prior to the creation of the DIMP variance account (2024 onwards). This includes full DIMP Admin and DIMP Project costs, as noted in Exhibit C, Tab 2, Schedule 14, Table 2, totaling $3.394 million and described in our filing.

   A portion of the Enhanced Distribution Integrity Management Program (EDIMP) Admin costs was also included as part of the overall Integrity Management Program prior to 2024. This includes Risk Management costs (risk model/assessment support), managerial/director/VP oversight, data management in information systems, and special surveys support for specific pipelines. The cost of these activities within the $0.946 million total is $0.258 million.

b) There is no stand-alone manual or guidance document that describes a prescribed methodology for determining which integrity, administrative, and overhead costs are

allocated under the DIMP and EDIMP programs. Rather, DIMP and EDIMP related costs are identified and charged based on the nature of the work being performed.

Please see the response at Exhibit I.FRPO-24 for the working definition used by Enbridge Gas to differentiate DIMP and EDIMP related work. O&M costs associated with DIMP and EDIMP related activities are recorded and reported through the DIMP and EDIMP programs, with the resulting program costs reflected in the DIMP Variance Account (DIMPVA).

Enbridge Gas reviews DIMP and EDIMP administrative and project costs on a monthly basis to evaluate year-to-date performance and validate that expenditures have been appropriately assigned to the programs based on the work performed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

The effectiveness of these activities is demonstrated by the combined capital cost avoidances of approximately $116.8 million associated with the NPS 12 Wilson Avenue, NPS 12 Martin Grove, and NPS 8 St. Thomas pipelines. [C/2/14, page 11]

Question(s):

a) Please provide a table of the capital cost avoidance related to each of the NPS 12 Wilson Avenue, NPS 12 Martin Grove, and NPS 8 St. Thomas pipelines and for each please indicate the year in which the capital avoidance occurs (if there is also a reference to the projects and original planned costs in the Asset Management Plan, please provide).

b) Please confirm that the $116.8 million in capital cost avoidances noted above are due to 2025 DIMP/eDIMP activities. If that is not correct, please provide a table on the capital avoidance per project (noted above) resulting from the following:
    - 2025 DIMP/eDIMP activities
    - 2024 DIMP/eDIMP activities
    - Other integrity related activities (note year if available)

Response:

a) The capital cost avoidance related to each of the NPS 12 Wilson Avenue, NPS 12 Martin Grove, and NPS 8 St. Thomas pipelines is described in Exhibit G, Tab 4, Schedule 1, pages 15 to 18. The information has been summarized in Table 1, below.

Table 1
Capital Cost Avoidance by Pipeline

Line No.	Pipeline	Capital Cost Avoidance ($ millions)	Year Recorded in ALE Scorecard
1	NPS 12 Wilson Avenue	$77.1	2026
2	NPS 12 Martin Grove	$34.3	2026
3	NPS 8 St. Thomas	$5.4	2026

Although each of the pipelines appeared in the most recent 2026 Asset Management Plan (AMP) Addendum[1], the costs included in the AMP are not directly used to determine the ALE capital cost avoidance. Rather, a Quantitative Risk Assessment (QRA) was completed for each pipeline to support a determination of whether the pipeline is fit-for-service (FFS) in the long-term. Whether a pipeline is determined to be FFS will determine the methodology used to calculate the associated Asset Life Extension (ALE) scorecard metric.

If a pipeline is determined to be FFS, the estimated cost of the avoided capital replacement project is included in the ALE scorecard metric. This was the case for the NPS 8 St. Thomas pipeline, and the estimated avoided capital replacement project cost of $5.4 million will be recorded in the 2026 ALE scorecard metric.

If the QRA identifies a pipeline as high-risk in its current condition, alternatives to reduce risk to tolerable levels are evaluated. In the cases of the NPS 12 Wilson Avenue and NPS 12 Martin Grove pipelines, two comprehensive, plausible, and feasible alternatives were identified for each that would effectively mitigate pipeline risk to acceptable levels. For each pipeline, a replacement option was compared against an inspect & repair option, including an evaluation using a Net Present Value (NPV) analysis that incorporated the long-term costs associated with each alternative. The difference in NPV between the inspect & repair option and the replacement option will be recorded in the 2026 ALE scorecard metric.

Please see Exhibit G, Tab 4, Schedule 1, pages 15 to 18 for more details.

b) Not confirmed. The $116.8 million of capital cost avoidance is not attributable to 2025 DIMP/EDIMP activities. Refer to Table 1 above for the capital cost avoidance by project.

As described in Exhibit G, Tab 4, Schedule 1, pages 15 to 18, the capital cost avoidances are associated with EDIMP pipelines that were inspected in 2024. QRAs

[1] EB-2020-0091; Enbridge Gas Asset Management Plan Addendum 2026; Appendix B; Investments #100339, #11443 and #100295.

for these pipelines were completed in 2025 using the inspection results obtained in 2024. The resulting ALE opportunities and associated capital cost avoidance will be recorded in the 2026 ALE scorecard metric.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Question(s):

a) Please provide the 2025 budgeted and actual HDDs that underpins the 2025 Average Use Variance Account balance recovery request.

b) Does Enbridge expect this trend to continue (i.e. lower actual average use compared to forecast) or is this estimated to be an anomaly. If this is a trend, please provide the information that Enbridge used to arrive at that conclusion.

Response:

a) Please see response at Exhibit I.FRPO-2, Attachment 2, Tables 7 and 8 for the 2025 actual and forecast HDDs that underpins the 2025 Average Use Variance Account (AUVA) balance. Rate 1 and Rate 6 consist of the Central weather zone, the East weather zone and the West weather zone. Rate M1 and Rate M2 consist of the South weather zone and Rate 01, and Rate 10 consist of the North weather zone.

b) Please see response at Exhibit I.STAFF-8 parts b and c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

Asset Life Extension Costs Deferral Account and DIMPVA

Question(s):

a) Please provide the balance (by year and total) in the Asset Life Extension Costs Deferral Account.

b) Please explain why it is appropriate to clear the DIMPVA on a final basis, but not review the Asset Life Extension Costs Deferral Account at the same time, given the relationship between these accounts.

Response:

a) Through 2025 no amount has been recorded in the Asset Life Extension Costs Deferral Account. Please see Exhibit C, Tab 2, Schedule 24, page 1, which lists the Asset Life Extension Costs Deferral Account as having no balance in 2025.

b) It is appropriate to clear the Distribution Integrity Management Program Variance Account (DIMPVA) annually on a final basis because the 2024 Rebasing Phase 1 Settlement Proposal expressly provides that variances will be recovered from or credited to ratepayers on an annual basis[1]. Although Enbridge Gas is also required to provide an annual report on DIMP and Enhanced Distribution Integrity Management Program (EDIMP) activities, there is no requirement for a specific outcome, such as a positive or immediate cost-benefit result, to be achieved in order for the costs incurred to be considered prudent. Rather, DIMP and EDIMP activities are intended to provide information on the condition of assets so that Enbridge Gas can assess and mitigate risk to tolerable levels.

   The purpose of the Asset Life Extension Costs Deferral Account is to allow Enbridge Gas to record incremental asset life extension O&M costs incurred following capital work that was deferred or eliminated as a result of findings from EDIMP activities. Please see Exhibit I.FRPO-28 for additional details. As described in Exhibit G, Tab

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.31.

4, Schedule 1, pages 11 to 13, there is a multi-year process between the inspection of a pipeline, completion of a Quantitative Risk Assessment (QRA), evaluation of long-term mitigation alternatives, and implementation of the preferred solution to reduce pipeline risk to tolerable levels.

Accordingly, the DIMPVA and the Asset Life Extension Costs Deferral Account serve different purposes and capture different types of costs that arise at different points in time. Each account should therefore be cleared when balances are recorded and become eligible for disposition, consistent with the intent established when the accounts were created.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

The balance in the IRP System Pruning Deferral Account for 2024 is $0.022 plus interest and for 2025 is $0.366 plus interest, for a total debit of $0.388 million, plus interest. Costs are associated with developing a System Pruning pilot approach and implementation of the pilot. [C/2/23]

Question(s):

a) Is this the first time the OEB is reviewing the IRP System Pruning Project and being requested to approve clearance of an amount in the IRP System Pruning Deferral Account? If no, please provide the references for the other OEB review and account clearance approval.

b) What OEB review is being relied on for approval of the IRP System Pruning Project and related costs incurred?

c) Please provide Enbridge's estimate of when the IRP System Pruning Project report will be filed (following project completion) and when residual costs would likely be requested for recovery via the IRP System Pruning Deferral Account.

Response:

a) This is the first time Enbridge Gas has requested clearance of the Integrated Resource Planning (IRP) System Pruning Deferral Account. As noted in Exhibit C, Tab 2, Schedule 23, page1, the 2024 amount was reported but not requested for recovery.

b) As outlined in the 2024 Rebasing Phase 2 Settlement Agreement, parties agreed that OEB approval is not required if the combined costs of the pilots are $5 million or less and the pilot(s) are supported by the IRP Technical Working Group[1] .

[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, p.20.

Enbridge Gas has reported on System Pruning in the 2024[2] and 2025[3] IRP Annual Reports filed in the Utility Earnings and Disposition of Deferral & Variance Account Applications. The costs requested for clearance were incurred for completed foundational activities and the associated reports and results of these activities have been filed in the IRP Annual Reports, with additional reporting on the results of the pre-screen form posted publicly on the OEB Natural Gas IRP webpage. Please see the response at Exhibit I.STAFF-13 part a) for the reports and results.

c) Enbridge Gas estimates the report on the IRP System Pruning Pilot Project will be filed in the 2026 Utility Earnings and Disposition of Deferral & Variance Account Balances Application. Final costs are expected to be requested for clearance in the 2027 Utility Earnings and Disposal of Deferral & Variance Account Balances Application.

[2] EB-2025-0155, Exhibit G, Tab 2, Schedule 1.
[3] Exhibit G, Tab 2, Schedule 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

The costs incurred include the following activities related to the System Pruning pilot include a) Jurisdictional Scan, b) Customer Research, c) Customer Engagement, and one Incremental IRP Staff.

Question(s):

a) Please provide a copy of the Jurisdictional Scan.
b) Please provide a copy of the final Customer Research Report (or available summary materials if a final report was not created).
c) Please provide a copy of the Customer Engagement (or available summary materials on purpose, scope and outcomes if an engagement plan was not created).
d) Please provide details on the incremental IRP staff hired for the pruning pilot and list how their objectives are different from other staff already funded through IRP. Was this an existing Enbridge Gas employee or an incremental external hire?
e) What is the 2025 IRP allocated headcount (not including the 1 FTE recorded in the IRP System Pruning Deferral Account) and annual costs and where are those recorded.

Response:

a-c) Please see response at Exhibit I.STAFF-13 part a) for the jurisdictional scan, customer research reports, and customer engagement pre-screen form and outcomes. A summary of the customer engagement purpose and scope is provided in the 2024 Integrated Resource Planning (IRP) Annual Report Appendix G.[1]

d) This role is currently staffed by an incremental external contractor. Their costs allocated to the IRP System Pruning deferral account are associated with development, consultation, implementation and reporting activities for System Pruning in accordance with the agreements outlined in Enbridge Gas 2024 Rate

[1] EB-2025-0064, Exhibit I.1.13-ED-4 Attachment 1, p.128

Rebasing Phase 2 Settlement Agreement.[2] This role does not support implementation of IRP more broadly.

e) In 2025 the IRP allocated headcount, excluding the System Pruning role, was 21.5 Full Time Employees (FTEs)[3]. This includes:

- 6 incremental resources required to execute the Southern Lake Huron (SLH) IRP pilot project requirements, whose costs are recorded in the IRP Operating Costs Deferral Account. Please see response at Exhibit I.STAFF-13 part b) for the SLH pilot project FTE costs.
- 15.5 resources who are responsible for ongoing IRP requirements, whose costs are included in the base O&M budget and rates. The 2025 salary, loadings and expenses actual costs for these FTEs was $2.394 million.

[2] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.19-20
[3] Regulatory FTEs responsible for IRP requirements are not included in this value as they are not directly allocated to IRP.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

As part of the 2024 Rebasing Phase 2 Settlement Proposal approved by the OEB, parties agreed that Enbridge Gas would develop its approach to system pruning in consultation with the IRP Technical Working Group by the end of Q2 of 2025 and begin implementation on one or two pilots by the end of Q1 of 2026. [C/2/23]

Question(s):

a) Please provide the materials provided to the IRP Technical Working Group related to the IRP Pruning Pilot that Enbridge is delivering.

b) Please provide the approval document (or IRP TWG comments if approval was not gained) related to the IRP Pruning Pilot that Enbridge is delivering.

Response:

a) Materials related to the Integrated Resource Planning (IRP) System Pruning Pilot that were provided to the IRP TWG and to the IRP TWG Subgroup[1] in 2024 and 2025 following the filing of the 2024 Rebasing Phase 2[2] Settlement Proposal are included in the attachments and link below:
    a. Materials provided by Enbridge Gas as part of IRP TWG meetings are included in Attachment 1.
    b. Materials provided by Enbridge Gas as part of IRP TWG Subgroup meetings are included in Attachment 2.
    c. Final versions of documents provided by Enbridge Gas to the IRP TWG for review and input are provided as follows:
        i. Request for Quotation for Jurisdictional Scan - Attachment 3

[1] A subcommittee of the IRP TWG ("IRP TWG Subgroup") was established to support detailed consultation on the jurisdictional scan and System Pruning approach.
[2] EB-2024-0111.

ii. System Pruning Pilot Project Approach – filed as part of the 2024 IRP Annual Report[3]

iii. Pre-screen form for customers - Attachment 3

iv. Outbound call script for delivery contractor - Attachment 3

d. Final versions of documents provided by Enbridge Gas to the IRP TWG Subgroup for review and input are included in Attachment 4:

i. Customer Research – System Pruning Focus Group Guide

ii. Customer Research – System Pruning Customer Survey

e. Final copy of documents that were provided by DNV to the IRP TWG:

i. Jurisdictional scan - link. The IRP TWG Subgroup provided feedback and DNV subsequently circulated the final report and presented it to the full IRP TWG for discussion.

b) IRP TWG support for the approach is outlined in the System Pruning Pilot Approach filed as Appendix G in the 2024 IRP Annual Report.[4] Subsequent confirmation of IRP TWG ongoing support prior to commencing field implementation of a pilot with eligible selected customers is recorded in the meeting notes from IRP TWG meeting #61 (December 3, 2025).[5]

[3] EB-2025-0064, Exhibit I.1.13-ED-4 Attachment 1, Appendix G, July 4, 2025.
[4] EB-2025-0064, Exhibit I.1.13-ED-4 Attachment 1, Appendix G, July 4, 2025, p.110
[5] OEB Engage with Us, Meeting #61 (December 3, 2025), Meeting Minutes (link), p.9

IRP Technical Working Group

Meeting #47

ENBRIDGE

November 20, 2024

Agenda

Agenda Item	Purpose	Time Allotted	Speaker(s)
Opening remarks / Preliminary matters	Inform	10 mins	Michael Parkes
Overview of 2025 – 2034 AMP Appendix B & Summary of IRP evaluation	Inform	30 mins	Helen Tong
Overview of key projects	Inform / Input	70 mins	Kurtis Lubbers / Helen Tong
System pruning update	Inform	10 mins	Whitney Wong

System Pruning Update

Phase 2 Settlement

Enbridge Gas will work with the IRP Technical Working Group to identify one or two system pruning pilot projects, which will be implemented by 2026

"The Parties agree that it is appropriate for Enbridge Gas to develop and implement a system pruning pilot project. The Parties have agreed that Enbridge Gas will develop its approach to system pruning in consultation with the IRP Technical Working Group by the end of Q2 of 2025 and begin implementation on one or two pilots by the end of Q1 of 2026.

The Parties agree that for these one or two pilots OEB approval is not required if the combined costs of these pilots are $5 million or less and the pilot(s) are supported by the IRP Technical Working Group.

The Parties agree that a new IRP System Pruning Deferral Account with a $5 million cap will be created for recording the incremental costs related to these activities for later recovery. Should Enbridge Gas forecast that the incremental costs of the IRP System Pruning pilot project(s) will exceed $5 million, then Enbridge Gas would be expected to seek OEB approval through an IRP Plan Application.

Key Takeaways

- By end of Q2 2025 develop approach for system pruning pilot(s)
- By end of Q1 2026 begin implementation of pilot(s)

System Pruning JScan Update

- DNV awarded contract to conduct jurisdictional scan

- Next steps / key milestones:
  - Confirm sub-committee members
  - Task 1 – Landscape Assessment – completed by end of November for TWG review

IRP Technical Working Group

Meeting #48

ENBRIDGE

December 4, 2024

2025 Workplan

System Pruning

Enbridge
Subcommittee
TWG

Item	January	February	March	April	May	June
Objectives, Data Sets and Criteria						
Identify / gather data sets - potential systems/criteria parameters						
Formalize objectives of pilot project(s)						
Develop criteria for candidate systems						
Agree on objectives and criteria for candidate systems						
Feedback on customer and IRP economic approach						
Assess economics for customer/system renewal alternative						
Apply criteria to potential candidate systems						
Review candidate system outcomes						
Initial Customer Offer Development/Outreach						
Develop offer approach						
Review / input on initial outreach approach and questions						
Agreement with TWG on initial offer / outreach approach						
Outreach with customers on potential systems						
Report on customer outreach results						
Finalize Approach						
Refine approach for system pruning pilot(s)						
Finalize approach for system pruning pilot(s)						

Jurisdictional scan workplan: January: Utility research
February: Commonalities, divergence, best practices, lessons learned, gaps (March final report)

IRP Technical Working Group

Meeting #49

ENBRIDGE®

March 19, 2025

Agenda

Agenda Item	Purpose	Time Allotted	Speaker(s)
Opening remarks / Preliminary matters	Inform	10 mins	Michael Parkes
Q1/Q2 Workplan	Inform	20 mins	Whitney Wong / Eric Buan
DCF+ Discussion	Discussion	1hr 30 mins	Margarita Suarez / Rich Szymanski

2025 Workplan

System Pruning

Enbridge
Subcommittee
TWG

Item	January	February	March	April	May	June
Pilot Objectives, Key Elements, Data set up						
Identify / gather data sets - potential systems / criteria parameters						
Formalize objectives of pilot project(s) and key elements of approach						
Develop criteria for candidate systems						
Agreement with TWG on objectives and criteria for candidate systems						
Apply criteria to potential candidate systems						
Review candidate system outcomes						
Customer Offer Development and Outreach						
Develop customer research approach						
Review / input on customer research approach / questions						
Review customer outreach results						
Develop basis of customer offer / outreach approach						
Review / input on initial offer / outreach approach						
Agreement with TWG on initial offer / outreach approach						
Develop financial analysis for customer/system renewal alternative						
Feedback on customer and IRP economic approach						
Finalize Approach (by end of Q2)						
Review refined approach for system pruning pilot(s)						
Finalize approach for system pruning pilot(s)						

Jurisdictional scan workplan: ***January:*** Landscape Assessment, Literature Review ***February – March:*** Utility interviews
March: Commonalities, divergence, best practices, lessons learned, gaps ***Final report:*** TBD

IRP Technical Working Group

Meeting #50

ENBRIDGE

March 26, 2025

Agenda

Agenda Item	Purpose	Time Allotted	Lead(s)
Opening Remarks / Preliminary matters	Inform	10 mins	Michael Parkes
System Pruning	Discussion	30 mins	Catherine McCowan
IRP Evaluation Update – Review of projects & DCF+ results	Discussion	1 hr 20 mins	Whitney Wong / Kurtis Lubbers / Helen Tong / Margarita Suarez

System Pruning

System Pruning Agenda

- Meeting objectives
- Work to date
- Elements of the approach
- Pilot objectives
- Pilot selection criteria
- Basis for customer offer

Meeting objectives

Settlement Agreement

> *The Parties have agreed that Enbridge Gas will develop its **approach** to system pruning in consultation with the IRP Technical Working Group by the end of Q2 of 2025 and begin implementation on one or two pilots by the end of Q1 of 2026.*

- Objectives today:
  - Share the work that has been done to date
  - Ensure ongoing alignment with a view to endorsement of the approach by Q2 2025

Work to date

- A jurisdictional scan is underway with DNV
  - Target jurisdictions have been identified (Quebec, New York, Colorado, California, Zurich) and a literature review has been completed
  - Interviews are in progress

- Enbridge has consulted with the TWG Subgroup to get input on the elements of the approach as they are developed
  - Work and progress to date shared in subsequent slides

- The approach will continue to evolve with input from the Technical Working Group, Jurisdictional Scan, and Customer Survey

Elements of the Approach

Enbridge has consulted with the TWG Subgroup to establish that these elements constitute the approach:

- Pilot Objectives
- Selection Criteria
- Customer Incentive
- Customer Engagement
- Customer Choice
- Stakeholder Engagement
- Program Delivery
- Implementation Plan

Pilot Objectives

- Understand customer perspective on disconnecting from the NG distribution system.
  - What are customer perceptions and how do these drive their decision-making?
- Understand customer reaction to incentives and whether they can be incented to disconnect from the system in a way that is economic relative to the replacement of the mains and services.
  - Other than economics, what factors positively or negatively impact customer desire to convert?
  - The goal is to learn and document what the factors are – not to "force" a customer off the system.
  - Customers will not be incented to move to a solution with higher overall emissions
- Understand what data or other information is relevant to collect for the IESO and LDC in the pilot area
  - There was some discussion that sub-metering of the hot water and space heating could yield useful information
- Understand what works and does not work in program delivery
  - In terms of targeting customers, is it more effective to have a broad program at the individual service level or a targeted program at the main section level?
  - Procurement and contracting with participating contractor(s)
    - Fair and equitable for contractors that have the skills to guide customers through the process of converting to electric appliances & equipment
  - Initial and ongoing communication to customers on the pilot systems
    - How does Enbridge establish the legitimacy of the contractors and the process?
  - Contractor payment structure to drive good customer experience and low cost of delivery.
- Understand what policy and framework elements need to be reconsidered by the Ontario Energy Board if system pruning is to become a broader program.
  - This will be on a best-efforts basis. The pilot, being small, is not likely to turn up all policy and framework needs.

Pilot Selection Criteria

- Cost of customer incentive is offset by the cost of the asset replacement – targeted assets will be part of System Renewal Capital.
- Structured data search will include the following criteria for consideration as pilot candidates:
  - Customers on dead end legs that are scheduled for replacement because of integrity & risk, eg vintage steel and Aldyl A
  - Customers with services scheduled for replacement because of integrity & risk, eg farm taps, AMP Fittings, isolated steel
- List will be reviewed with Operations, Integrity and Asset Management to identify omissions or inclusions.
- Enbridge will attempt to include at least one commercial customer in the pilot.
- Review with the LDC's and Municipalities to make sure there are no concerns in the area for electrical reliability, incorporating datasets from LDC/IESO if available.
- Customer survey to establish initial response to electrification and increase likelihood that all pilot steps can be executed.

Basis for the Customer Offer

- Wide range of technologies (price, performance) available for customers to convert their equipment and appliances from natural gas to electricity
- Customer offer will aim to provide customers with comparable equipment and similar features:
  - Catalogue of similar appliances to be developed to support the contractors that are delivering the service.
  - Customers can install different technologies or upgrades at their expense
  - Customers will be made aware of rebates that may be available to improve the energy efficiency of the building and lower the heating and cooling requirements.
- In addition to the appliances and equipment, the offer will cover the work to remove the natural gas appliances, equipment, and gas piping from the home, install the electric equipment and appliances, and perform any upgrades to the electrical system in the home.
- Key themes to ensure when considering the approach to customer offer (informed by focus groups):
  - Customer satisfaction, fairness, transparency and consistency in offer
  - Will be flexible to encourage participation (i.e. customer needs may vary depending on duct work, electrical infrastructure) but focus will be to ensure customers are treated equitably with respect to quality and aesthetics of the appliances/equipment.

Note: Customer research and the jurisdictional scan may provide additional insight and changes in the customer offer

Customer Offer

Appliance	Most common replacement option (subject to review with the homeowner)
Natural Gas Furnace	Cold climate air source heat pump with electric backup
Natural Gas Boiler / Hydronic System	Air to water heat pump with electric backup
Natural Gas Water Heater	Heat pump hot water heater or electric water heater (tank or tankless)
Natural Gas Cooktop / Stove	Induction stove (same number of burners)
Natural Gas Oven	Electric oven
Natural Gas Fireplace	Electric fireplace
Natural Gas Clothes Dryer	Electric clothes dryer
Natural Gas Barbecue	Propane BBQ
Natural Gas Pool heater	Air source heat pump for pool

Note: Appliances and equipment with an Energy Star rating or similar will be installed.

Next Steps

- Customer Research will begin March 31st:
  - Understand what factors customers consider when determining whether to disconnect from the natural gas distribution system
  - Test what elements of the Customer Offer are attractive to customers and where other incentives are required to encourage them to disconnect
- A communications strategy is being developed to engage with customers and make sure that they are informed and supported through the pruning pilot.
- A contractor strategy is being developed to identify contractors with the right skills to deliver these programs to customers.

Questions?

IRP Technical Working Group

Meeting #52

ENBRIDGE®

April 23, 2025

Agenda

Agenda Item	Purpose	Time Allotted	Lead(s)
Opening remarks / Preliminary matters	Inform	10 mins	Michael Parkes
IRP Pilot update and workplan timelines	Discussion	30 mins	Eric Buan
IRP Annual Report timelines	Inform	10 mins	Whitney Wong
System Pruning update	Inform / Discussion	30 mins	Catherine McCowan
Framework Review	Discussion	40 mins	Michael Parkes

System Pruning update

For Discussion

- Updates from March 26th TWG Meeting
  - Elements of the Approach
  - Pilot Objectives
  - Selection Criteria
- Contractor Strategy
- Evaluation Strategy
- Workplan to develop Approach

* Updates following the March 26th meeting of the Technical Working Group are in bold on each slide

Elements of the Approach

Enbridge has consulted with the TWG Subgroup to establish that these elements constitute the approach:

- Pilot Objectives
- Selection Criteria
- Customer Incentive
- Customer Engagement
- Customer Choice
- Stakeholder Engagement
- Program Delivery
- Implementation Plan
- Evaluation Strategy

Pilot Objectives

- Understand customer perspective on disconnecting from the NG distribution system.
  - What are customer perceptions and how do these drive their decision-making?
- Understand customer reaction to incentives and whether they can be incented to disconnect from the system in a way that is economic relative to the replacement of the mains and services.
  - Other than economics, what factors positively or negatively impact customer desire to convert?
  - The goal is to learn and document what the factors are – not to "force" a customer off the system.
  - ~~Customers will not be incented to move to a solution with higher overall emissions~~
  - **While the pilot itself does not have to be economic, economics will be a consideration in the selection criteria where preliminary financial analysis will identify outliers to be avoided.**
- Understand what data or other information is relevant to collect for the IESO and LDC in the pilot area
  - There was some discussion that sub-metering of the hot water and space heating could yield useful information
- Understand what works and does not work in program delivery
  - In terms of targeting customers, is it more effective to have a broad program at the individual service level or a targeted program at the main section level?
  - Procurement and contracting with participating contractor(s)
    - Fair and equitable for contractors that have the skills to guide customers through the process of converting to electric appliances & equipment
  - Initial and ongoing communication to customers on the pilot systems
    - How does Enbridge establish the legitimacy of the contractors and the process?
  - Contractor payment structure to drive good customer experience and low cost of delivery.
- Understand what policy and framework elements need to be reconsidered by the Ontario Energy Board if system pruning is to become a broader program.
  - This will be on a best-efforts basis. The pilot, being small, is not likely to turn up all policy and framework needs.

Pilot Selection - Sample Population Criteria

- Structured data search will include the following criteria for consideration as pilot candidates:
  - Targeted assets will be a part of the System Renewal Capital (i.e. cost of customer incentive is offset by the cost of the asset replacement)
  - Customers on dead end legs that are scheduled for replacement because of integrity & risk (E.g. vintage steel and Aldyl A)
  - Customers with services scheduled for replacement because of integrity & risk (E.g. farm taps, AMP Fittings, isolated steel)
- List will be reviewed with Operations, Integrity and Asset Management to identify omissions or inclusions.
- There are many mains and customers (~100,000) that meet the above criteria for consideration as a potential pilot candidate

Pilot Selection

- Propose two pilots:
  - Single main with ~10 customers on it and;
  - ~ 10 individual services that are scheduled for replacement.
- Enbridge will attempt to include at least one commercial customer in the pilot.
  - Agreement with TWG that this must be a customer where the decision-making for heating and cooling is limited to the building owner.
- *(In development)* The selection and pre-screening process to narrow down the list of potential pilot candidates to include consideration for:
  - Economics through preliminary financial analysis, including identifying outliers
  - Review with the LDC's and Municipalities to make sure there are no concerns in the area for electrical reliability, incorporating datasets from LDC/IESO if available.
  - Operational efficiency, pilot(s) can be effectively served by contractor
  - Pre-screening customer survey to establish initial response to electrification and increase likelihood that all pilot steps can be executed.
  - Diversity, i.e. customer type, home vintage, income, initial response

Contractor Strategy

- RFI issued April 14th to better understand how the services can be delivered.
- Issued to:
  - Summerhill
  - CLEAR Result
  - The Home Inspectors Group
  - EnviroCentre
  - Green Communities
  - Dunsky Energy + Climate Advisors

Evaluation Strategy

- The evaluation will compare Pilot Outcomes to the Pilot Objectives
- Financial analysis
  - Cost per conversion – compare actual versus estimated cost for each pilot customer (whether that customer chose to disconnect or remain on the system)
  - Change in energy bills
  - Consider variance by household type, equipment choice etc.
- Customer uptake
  - % uptake rate - compare actual uptake relative to the general survey (April) and the pre-screen
  - Consider influencing factors and/or characteristics of the participants/home
  - Customer rationale for participating/not-participating
- Program delivery effectiveness
  - Customer satisfaction/trust – post-installation survey for feedback
- Transferability of learnings
  - Understand the applicable transferability of the characteristics of the pilot location and customers to others in the gas distribution system

Workplan to Develop Approach

- Enbridge is seeking endorsement of its Approach for the System Pruning Pilot by Q2 2025. **Seeking confirmation of workplan deliverables**

Approach Element	Deliverables/Remaining Work
Pilot Objectives	Complete
Selection Criteria and Process	Sample population criteria – Complete Selection process – In Progress (inclusive of financial comparison of facility & non-facility alternatives)
Customer Offer	Pending input from Jurisdictional Scan and Customer Research
Customer Engagement	Complete – materials and questionnaires to be developed in pilot rollout
Customer Choice	In Progress – Flexibility Guidelines to be developed and bounded with Financial Analysis
Stakeholder Engagement	In Progress – meeting with IESO scheduled. LDC meeting pending identification of pilot location.
Program Delivery	General approach – Complete. Additional details following input from RFI
Implementation Plan	General approach – Complete. Additional details following input from RFI and based on field experience.
Evaluation Strategy	In Progress – meeting with DNV scheduled for insights.

IRP Technical Working Group

Meeting #53

ENBRIDGE®

May 7, 2025

Agenda

Agenda Item	Purpose	Time Allotted	Lead(s)
Opening Remarks / Preliminary matters	Inform	10 mins	Michael Parkes
IRP Pilot Update – Objective 1 (Peak Hour)	Inform / Discussion	50 mins	Kurtis Lubbers
System Pruning update	Inform / Discussion	25 mins	Catherine McCowan
Annual Report schedule	Inform	5 mins	Whitney Wong / Mike Parkes
Framework Review	Discussion	30 mins	Michael Parkes

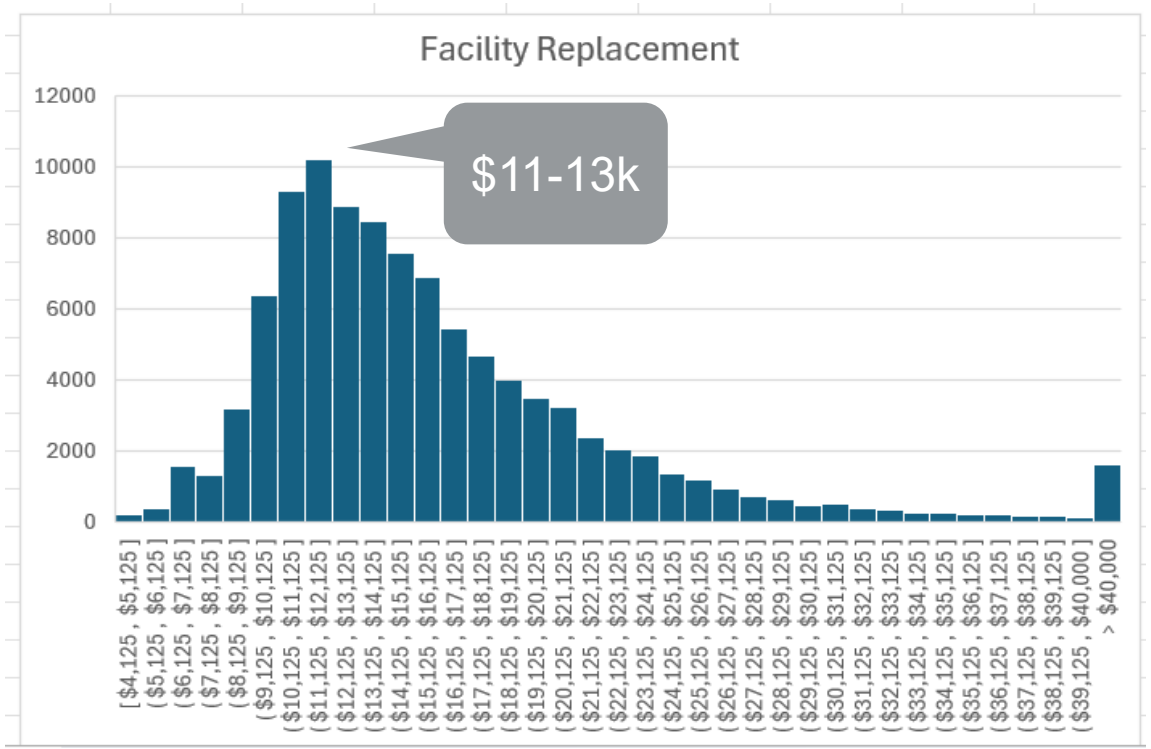
System Pruning update

Filed: 2026-10-29, EB-2026-0108,Exhibit I.PP-12, Attachment 1, Page 40 of 106

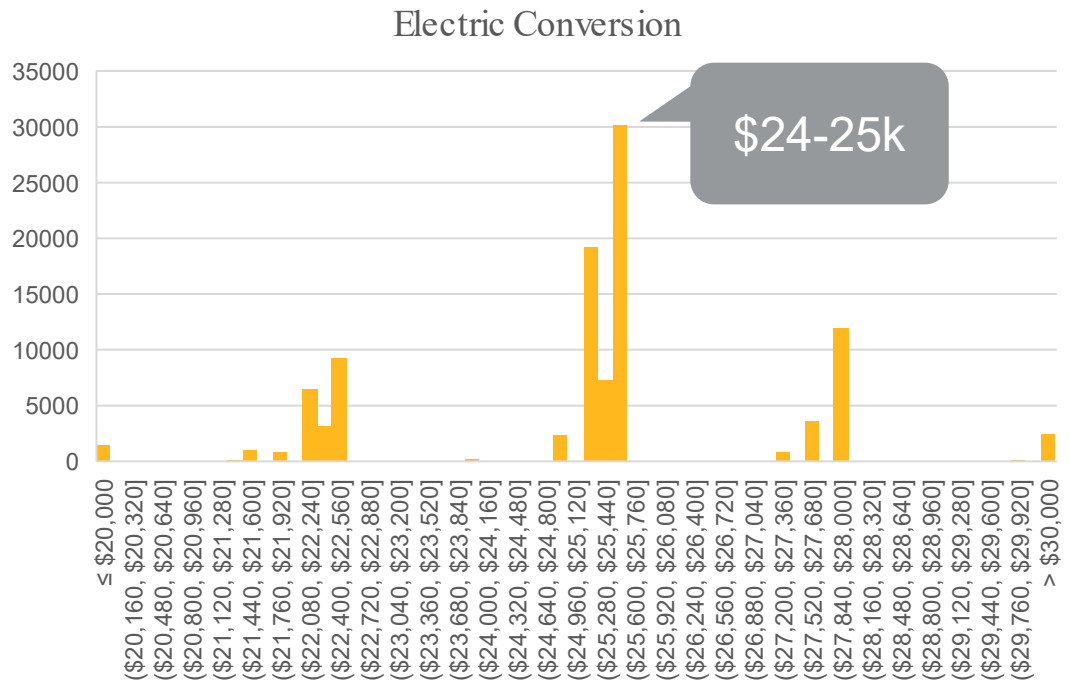
Cost Comparison – Model Inputs

- Customer Data
  - Region, main & service information
- MPAC Data
  - Size and age of home (category)
- End-use Survey Data
  - % of customers that use gas for various purposes by Region
- Cost Data (data source)
  - Replacement costs for mains & services (Operations - based on 2024 actuals for two projects, no differentiation between relay and AMP fitting replacement)
  - Upgrade cost for electric panel and new service (seeking input)
  - Replacement cost for BBQ, Fireplace (from RONA)
  - Installation of Heat Pump and Electric Backup (seeking input)
  - Replacement cost for HP Hot Water Heater (from Home Depot/RONA)
  - Extras for installation and upgrades (seeking input)

Cost Comparison



	Min	Max
Facility Replacement	$<4k (service/riser replacement only)	> $1M (long main)
Electric Conversion	~$20k (small, new home with heating & hot water)	$50k+ (large, old home with all appliances)



- Conversion costs do not include the utility bill, pool heaters, dryers, generator, incidentals, stove/oven, or contractor costs
- Installed HP Costs from Posterity Study, upper/lower quartile
- Posterity study for HP HW are significantly higher than what is included here ~$12k higher installed

* Note: The facility replacement chart is based on LUG data. LEG is similar with AMP Fittings causing a spike on the far left.

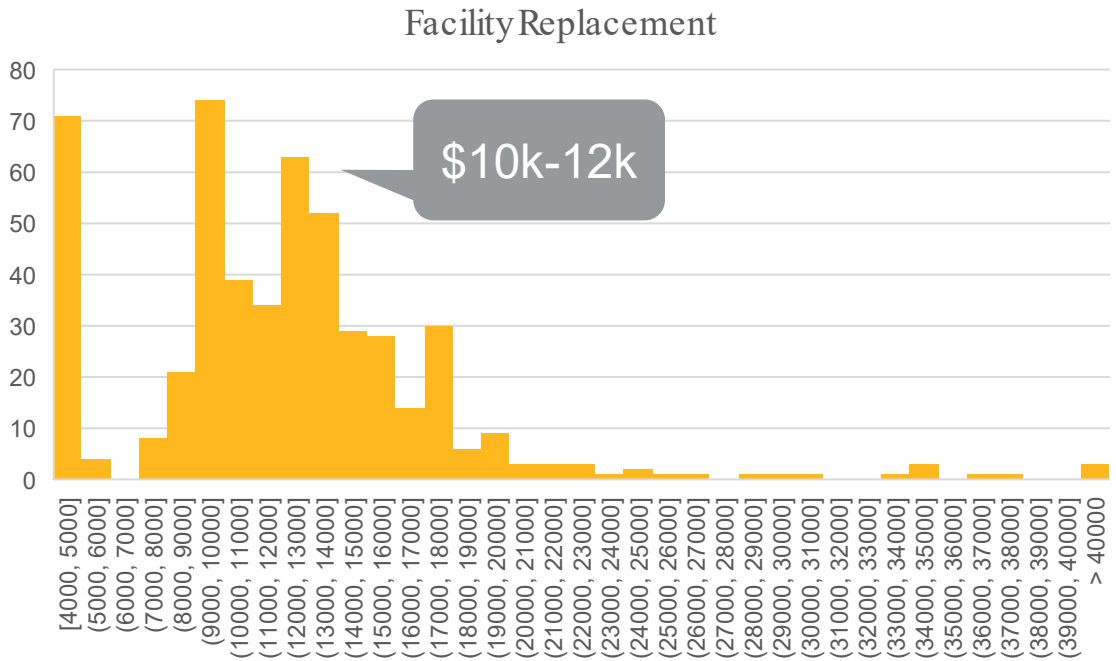
Implications for Pilot

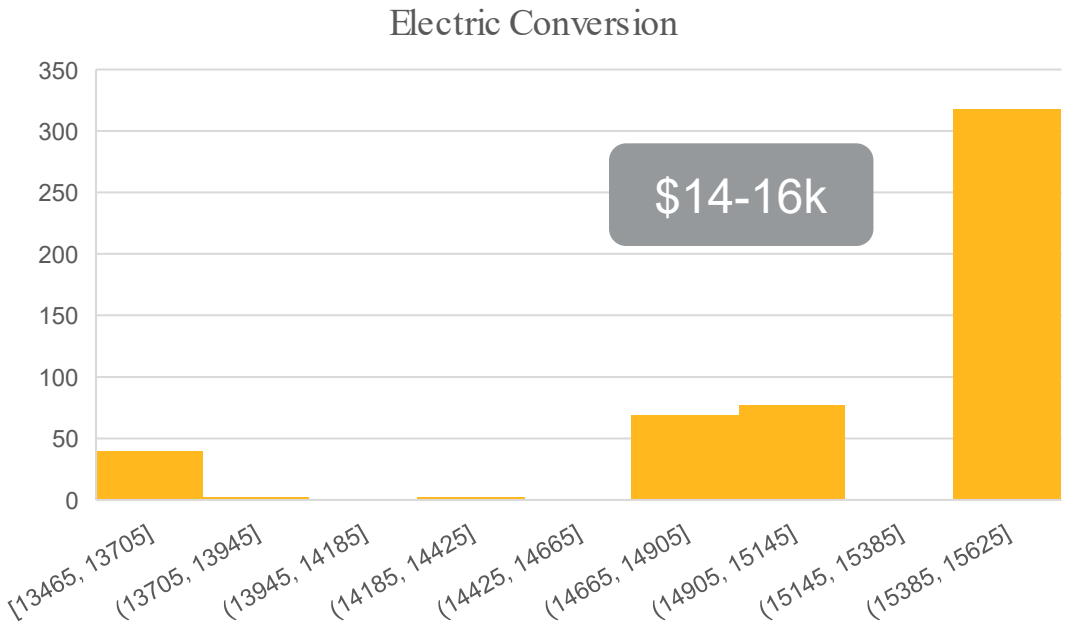
- Residential conversion where the facility replacement is service-only, are not generally economic.
  - Should we exclude the single residential services and AMP Fittings?
  - Should we consider finding an individual commercial customer where the economics might be better?
  - Would it be better to conduct 2 pilots that are street level with different demographics – location, size, age, income, etc.?

- To what extent should we factor in the economics?
  - For example, should we focus the pilot on: Area with “newer”, smaller homes?

Size less thank 1500 sq. Ft, Built after 1974, remove single services

Newer, smaller homes in LEG area





- This does not change the assumptions about the adoption of other gas appliances in the home.
  E.g. although the house is smaller, the same distribution of 1, 2 and 3+ gas fireplaces is assumed.

Filed: 2026-10-29, EB-2026-0108,Exhibit I.PP-12, Attachment 1, Page 44 of 106

Mains & Service Replacement & Abandonment ($ Assumptions)

Service Replacement Cost				
	Replacement Cost		Service Abandonment	
GTA EAST & TORONTO	$	4,000	$	2,000
GTA WEST	$	4,000	$	2,000
NORTHERN & EASTERN REGION	$	6,000	$	3,000
SOUTHEAST REGION	$	6,000	$	3,000
SOUTHWEST REGION	$	6,000	$	3,000

Main Replacement Cost per Meter				
	Replacement Cost per meter		Abandonment beyond sectionig at each customer	
GTA EAST & TORONTO	$	1,000	$	2,000
GTA WEST	$	1,000	$	2,000
NORTHERN & EASTERN REGION	$	600	$	1,200
SOUTHEAST REGION	$	600	$	1,200
SOUTHWEST REGION	$	600	$	1,200

Costs based on a small sample of projects completed in 2024.

Main abandonment assumes that a section can be taken at residential services and allows for 2m of work to cut and cap the remaining main.

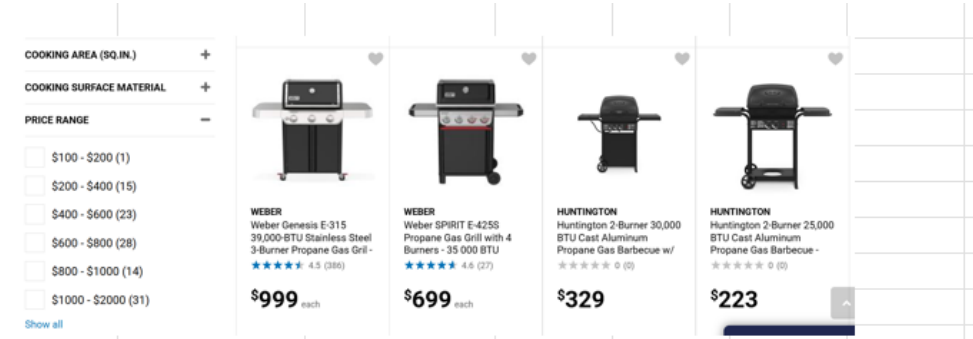
Service abandonment assumes ½ the cost of a service replacement.

Filed: 2026-10-29, EB-2026-0108,Exhibit I.PP-12, Attachment 1, Page 45 of 106

BBQ & Fireplace ($ Assumptions)

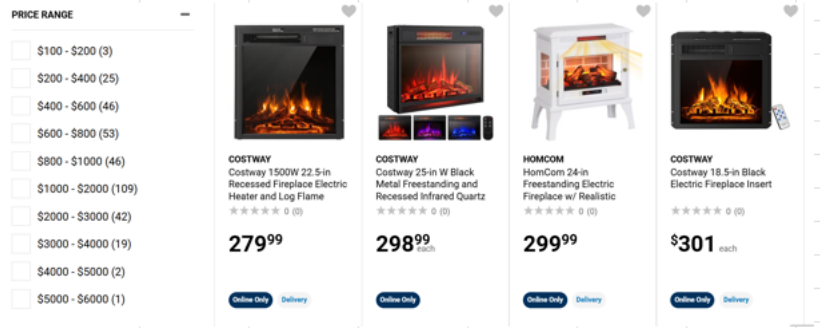
Cost to Replace Natural Gas BBQ

	% of People that have a NG BBQ (Source 2024 end-use survey, p. 14)		
GTA EAST & TORONTO	26%		
GTA WEST	35%		
NORTHERN & EASTERN REGION	21%		
SOUTHEAST REGION	29%		
SOUTHWEST REGION	33%		
Price for Propane Replacement I	$	700	mid-range of median
Price for Installation/Setup	$	100	



Cost to Replace Natural Gas Fireplaces

	% that have a fireplace		% of those with 1	% of those with 2	% of those with 3	Weighted Cost	
GTA EAST & TORONTO	35%		73%	23%	4%	$	504.35
GTA WEST	51%		73%	24%	3%	$	729.30
NORTHERN & EASTERN REGION	34%		75%	25%	3%	$	501.16
SOUTHEAST REGION	37%		67%	27%	5%	$	553.52
SOUTHWEST REGION	37%		74%	23%	3%	$	525.03
Price for Electric Replacement F	$	1,000	Median				
Price for Installation/Setup	$	100					

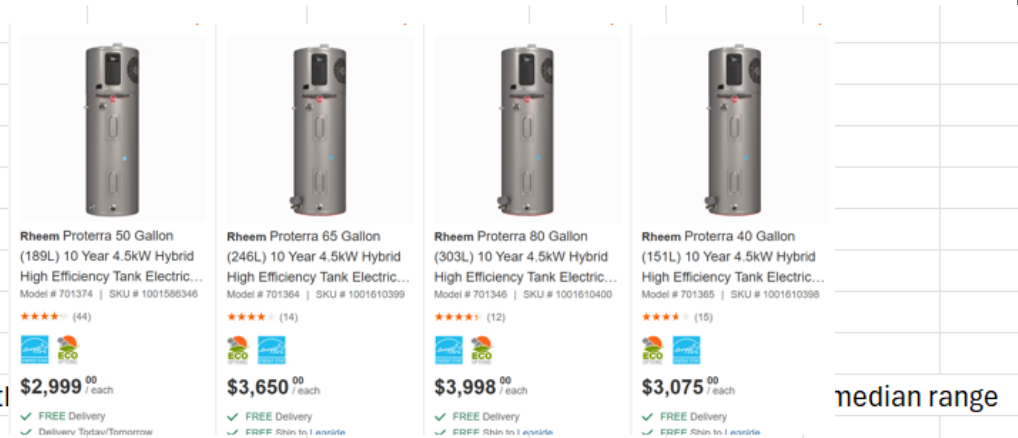


Filed: 2026-10-29, EB-2026-0108,Exhibit I.PP-12, Attachment 1, Page 46 of 106

Heat Pump & Hot Water ($ Assumptions)

Home Age	Category	Sq Foot	Cost			
1974 and older	1	1	$ 14,000		Mean	$ 14,000
1974 and older	1	2	$ 16,500			$ 16,500
1974 and older	1	3	$ 19,000		Top quartile	$ 19,000
1975-2006	2	1	$ 11,000			$ 11,000
1975-2006	2	2	$ 14,000		Mean	$ 14,000
1975-2006	2	3	$ 16,500			$ 16,500
2007 and newer	3	1	$ 8,000		Bottom Quartile	$ 8,000
2007 and newer	3	2	$ 11,000			$ 11,000
2007 and newer	3	3	$ 14,000		Mean	$ 14,000

	Tank	Tankless	Blended Cost
GTA EAST & TORONTO	58%	16%	$ 2,133
GTA WEST	68%	13%	$ 2,456
NORTHERN & EASTERN REGION	62%	14%	$ 2,252
SOUTHEAST REGION	69%	13%	$ 2,488
SOUTHWEST REGION	66%	14%	$ 2,382
Cost of Electric Tank Water Heat	3300		
Cost of Installation (Tank)	100		
Cost of Electric Tankless Water H	800	Tankless are not HP.	Cannot separate tankless in tl
Cost of Installation (Tankless)	300		



median range

Filed: 2026-10-29, EB-2026-0108,Exhibit I.PP-12, Attachment 1, Page 47 of 106

Electric Upgrades ($ Assumptions)

	2000	Break year for 200A Service
$	1,000	Cost to Upgrade Panel
$	3,000	Cost to Upgrade Customer Electrical Service

- Enbridge will review the electrical upgrades that are required for each customer – dependent on the equipment that they already have and will be flexible in its approach

Workplan to Develop Approach

Approach Element	Feedback	Endorsed
Pilot Objectives	Complete	Complete
Selection Criteria and Process		
Sample population & criteria	Complete	Complete
Use customer survey results to identify demographics for likely adoption	May 7th	May 21st
Use Financial Analysis to identify customers where it is reasonable to convert	May 7th	May 21st
Customer Offer		
Preliminary	Complete	Complete
Updated to reflect Customer Survey	May 15th	May 21st
Updated to reflect Jurisdictional Scan	TBD	TBD
Customer Engagement	Complete	Complete
Customer Choice		
Preliminary	Complete	Complete
Interplay of Flexibility & Financial Analysis	May 7th	May 21st
Stakeholder Engagement	Complete	Complete
Program Delivery		
General	Complete	Complete
With input from RFI	May 15th (SG)	May 21st (TWG)
Implementation Plan	Complete	Complete
Evaluation Strategy (internal note, meeting scheduled with DNV for input)	May 7th	May 21st

- Element updates May 7th & 21st.
- Draft Approach issued May 30th
- Discuss Draft Report June 4th
- Written comments to Enbridge June 6th
- Discuss written comments June 18th
- Final endorsement June 23rd
- Annual Report filed June 27th

IRP Technical Working Group

Meeting #54

ENBRIDGE®

May 21, 2025

Agenda

Agenda Item	Purpose	Time Allotted	Lead(s)
Opening Remarks / Preliminary matters	Inform	10 mins	Michael Parkes
Framework Review	Discussion	60 mins	Michael Parkes
System Pruning update	Discussion	20 mins	Catherine McCowan
Annual Report Feedback	Discussion	30 mins	Whitney Wong

System Pruning Update

Agenda

- Customer Research update for awareness
  - Customer Survey Summary report (included as separate attachment)
  - Customer Research Slides from TWG Subgroup (included as Appendix slides)
- Incorporation of Customer Research into Customer Offer (with updates based on TWG Subgroup feedback)
- Incorporation of Customer Research into Selection Process (adjusted approach based on further analysis)
- Request for Information (RFI) findings

Updates following TWG Subgroup are in bold

Customer Offer (recommendation)

- **Customer Research** shows that beyond the base offer of appliances and equipment, customers value different things.
- The preliminary **Financial Analysis** shows that conversion to electricity will not be economic in most cases.
- Recommended Offer:
  - Keep the **base offer** for all customers, this includes new equipment/appliances, the labour and materials to install them, labour and equipment to remove old equipment and their gas infrastructure, as well as make any electrical panel/service upgrades.
  - Customers may choose upgrades to the offer at their own expense.
  - Customer **will be offered** an Energy Audit at no cost, and information about the upgrades and rebates that are available to improve the energy efficiency of the home. During implementation, **expectation is that the Energy Audit will provide guidance on expected change to utility bills, and this will be discussed with the general contractor.**
  - Most customers value an extended warranty/guarantee on the work & equipment. If this can be arranged through the general contractor, then it **will be included** as part of the offer.
  - Provide customers with an additional amount of $XXX which they can use to:
    - > Offset increased energy costs (to be determined in consultation with the local LDC, for an amount equivalent to 5 years). Since it is not clear at this time whether the customer costs will go up or down, complete an analysis once the pilot area is selected and include an amount that covers 3-5 years of this extra.
      - Considering this as upfront payment informed by analysis - actual bill impacts will be influenced by usage changes beyond changes to the equipment
      - Given 59% perceive their energy costs will go up, beyond analysis/education may need to layer in payment as component of flexibility in implementation
    - > Cover incidental costs if they need to take a day off work, make small repairs after equipment and appliance exchanges have been completed, or for other disruptions they may experience

Selection Process (Updated following TWG Subgroup)

- Used the results from Customer Research to narrow down the Cities
  - The sample is small, but customer research reveals different customer segments with different likelihoods for participation
  - First cut, looked at cities with at least 20 respondents, and more than 40% of the customers likely to participate.
- Beyond this, Enbridge identified customers with an expected Facility Replacement Cost > $40k.
  - This left a small number of customers (fewer than 70 across both LEG and LUG)
  - Lowering the threshold to <$30k and <$20k left fewer than 130 customers and 1800 customers, respectively.
- Also discussed at the TWG Subgroup was the apparent under-representation of LUG cities
- Since the TWG Subgroup, an error in the selection methodologies was detected and corrected; and the criteria were relaxed to provide a greater number of candidate customers with which to begin pre-screening.
  - Pre-screening will still start with the customers for which facility replacement is expected to be more expensive.

Selection Process (Updated following TWG Subgroup)

- Cities are selected if there are 5 or more respondents and a 40% or more positive response to the offer
  - Positive response / likely (to participate if system pruning was a project in your area) is defined as customers who are definitely or somewhat likely to participate after seeing the base offer
  - Tables to the right show cities (split by LUG and LEGD) and associated # of candidate customers that meet the criteria above
- Facility costs then layered on top to determine total # of candidate customers in each cost category

Cost per Customer	Legacy UG	Legacy EGD	Total # of candidate customers
>$40k	59	119	278
>$30k	211	282	493
>$20k	1,318	2,357	3,675
All	7,624	34,595	42,219

City (LUG)	# of Customers
BELLEVILLE	583
BRANTFORD	571
BURLINGTON	1137
ESPANOLA	213
HAMILTON	2592
LONDON	724
OAKVILLE	863
PICTON	300
STRATFORD	641
Grand Total	**7624**

City (LEGD)	# of Customers
AJAX	208
BARRIE	995
BRADFORD	182
BRAMPTON	3447
BROCKVILLE	249
COLLINGWOOD	140
ETOBICOKE	3192
GLOUCESTER	1132
GRIMSBY	84
MISSISSAUGA	2640
NEPEAN	1012
NEWMARKET	284
NIAGARA FALLS	1590
NIAGARA ON THE LAKE	158
ORANGEVILLE	163
ORLEANS	971
OSHAWA	1180
OTTAWA	1290
PELHAM	178
PETERBOROUGH	593
PICKERING	423
RICHMOND HILL	369
SCARBOROUGH	9041
ST CATHARINES	3162
THORNHILL	905
THOROLD	373
TORONTO	82
WAINFLEET	28
WELLAND	524
Grand Total	**34595**

Selection Process Next Steps

- Enbridge will bring data together to create a short list of pilot areas for consideration, filtered down using the following:
  - Financial analysis (or specific knowledge of commercial customers) shows facility replacement costs are high.
    - > From the financial analysis, Enbridge has found that some of the customers with a high facility replacement costs are single customers with main.
  - Customers are generally more positive about electrification (based on Customer Research)
  - LDC can support electrification with existing infrastructure or planned upgrades (setting up discussions now).
    - > **TWG requested that we include an understanding of the marginal electricity rates in each area.**

Selection Process & Implementation Next Steps

- Proposed Pilots
  - One pilot with ~10 customers on a single street and;
  - One pilot with ~ 10 individual customers (residential or commercial)
- As part of implementation, Enbridge will engage customers through a pre-screening process to identify sentiment, appliances, and other demographics
  - A street level pilot with a mix of sentiments will provide greater learnings.
    - TWG preference is with a small pilot, no Opposers should be included in the street level pilot. An Opposer could be included in the individual customers as a way of understanding what it takes to convert them to electricity. The Opposer must, at a minimum, be willing to meet with the general contractor.
  - A street where at least some customers have more than space and water heating with natural gas will provide greater learnings.
  - Individual services will be in a different community to that of the street-level pilot and will seek to represent varying house size, sentiment, appliances, income.
  - Pilot selection will depend on the feedback through pre-screening and the pilot locations may need to vary to include two streets in the event individual customers are all strong "Opposers" in pre-screen, which will also inform learnings

Request for Information (RFI) Findings

- Enbridge issued an RFI to understand how contractors would deliver the more qualitative aspects of the service (unbiased, customer-focused) and how the contract should be structured to support this while maintaining project timelines and cost-effectiveness.
- Contractors provided ways in which they believe that they can deliver information that is fuel agnostic and unbiased with respect to specific equipment manufacturers.
- Contractors provided cost structures that include:
  - A Project Setup fee to develop processes, survey instruments, any materials that are to be left with customers, and training.
  - A per customer fee that covers the introductory discussion(s) with customers, inventory of appliances, discussion of alternatives and performance of building calculations
  - A fee to execute the work – most have proposed that this is variable because of the range of services that each customer may need.
- Some have contemplated a number of extras, including ongoing advice service for customers to help them keep energy costs low.
- Enbridge will incorporate these findings into the procurement process during pilot execution

Appendix

Customer Research Presentation from May 15th SG Meeting

Filed: 2026-10-29, EB-2026-0108,Exhibit I.PP-12, Attachment 1, Page 60 of 106

Customer Demographics and Equipment Results

- Customers – live in older (and smaller) homes, same household size as customer population
  - 65% less than 2000 sq ft, 94% built before 1990 (customer reported – not MPAC)
  - 53% have 1 or 2 people living in them
  - 69% have no plans to sell in the next year
- Equipment – mostly similar to customer population
  - 86% have a natural gas furnace for primary heat; 5% have heat pump
    - > 92% back their ASHP up with natural gas in some form
  - 80% have natural gas for hot water heating
  - These customers have about the same number of appliances
    - > Lower penetration of stoves/ovens which is a high-cost item to replace
    - > Higher penetration of pool heaters which is a high-cost item to replace
  - Likelihood to replace equipment in next two years does not appear to be different for this group

Natural Gas Penetration across Equipment	% from System Pruning Survey	% from 2024 Residential End Use Survey*
Home Heating – Furnaces (ASHP)	86% (5%)	79% (5%)
Water Heating	80%	78%
Fireplace	33%	37%
Cooktop/ Stove/Oven	26%	31%
BBQ	23%	21%
Clothes dryer	11%	13%
Pool heater	8%	4%
Generator	2%	n/a

Methodology and survey questions varied for each of these surveys and may explain some of the differences in results.

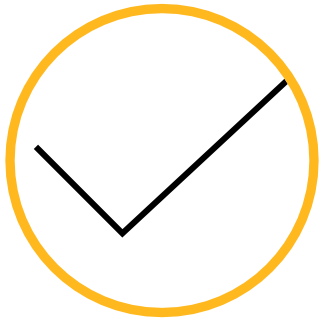
Respondent Segments: Mapping Disconnection Attitudes

- While most customers did not change their mind (67%) after seeing the additional offer elements, some became more interested, while others less so.



"Strong Adopters"

- 10% of respondents
- Already fully on board
- 'Definitely likely' to disconnect *before* and *after* reviewing the additional offer elements



"The Leaners"

- 23% of respondents
- They're leaning in, but may still need persuasion
- 'Somewhat likely' to disconnect *before* and *after* reviewing the additional offer elements



"The Persuadables" (Switched Up)

- 13% of respondents
- The offer worked – this group was influenced
- Switched *up* to 'Definitely/ Somewhat likely' to disconnect *after* reviewing the additional offer elements



"The Waverers" (Switched Down)

- 9% of respondents
- Initially open but lost interest/trust after reviewing offer elements
- Switched *down* to 'Somewhat//Not very/Not at all likely' to disconnect *after* reviewing the additional offer elements



"The Opposers"

- 31% of respondents
- Unmoved from the start – likely have strong objections
- 'Not very/Not at all likely' to disconnect *before* and *after* reviewing the additional offer elements



"The Fence Sitters"

- 14% of respondents
- Indicated 'don't know' *after* reviewing the additional offer elements

*Segments based on the initial sentiment and reaction to the offer components, specifically Q14 (initial likelihood of disconnection after reviewing the base offer) and Q28 (likelihood of disconnection after evaluating offer elements).
Note: This analysis was conducted by the Enbridge Gas Customer and Market Insights team to provide insights during the analysis and review period. It is not part of the final report and is intended to support targeted engagement by highlighting patterns across key audience groups. Please note that these groups are different from the groups presented in the final report.

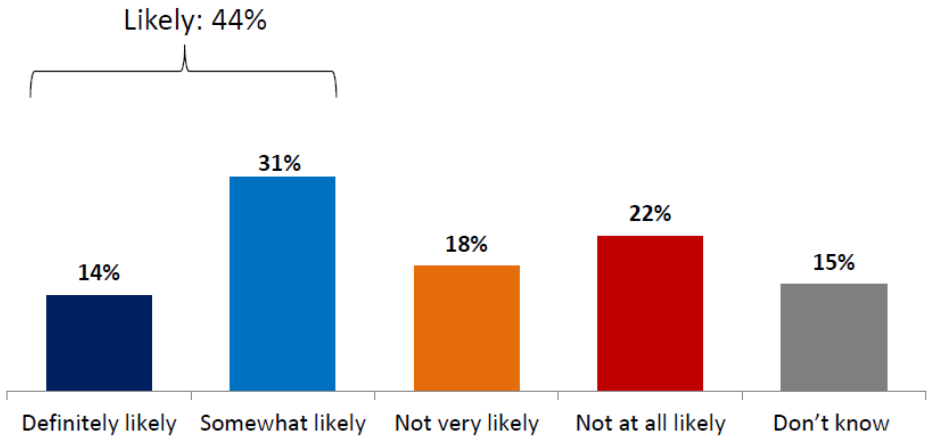
Filed: 2026-10-29, EB-2026-0108,Exhibit I.PP-12, Attachment 1, Page 62 of 106

Elements of the Customer Offer

After Seeing the Base Offer:

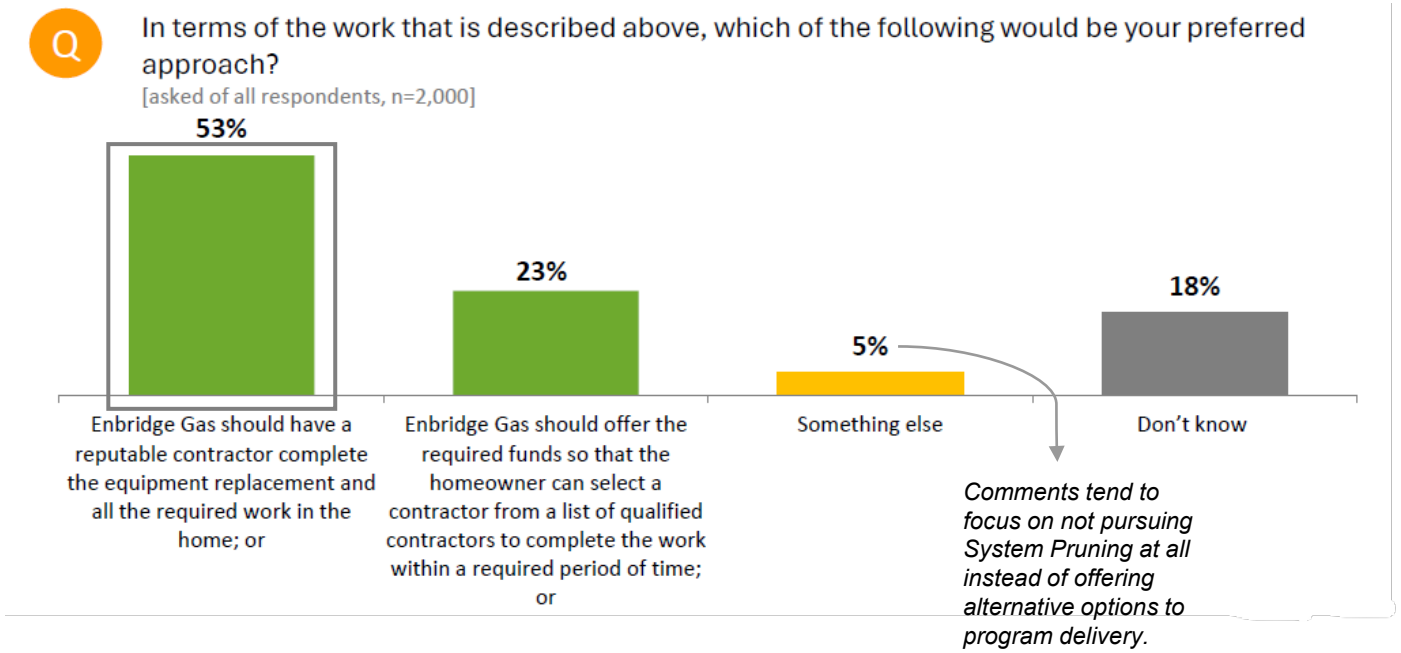
- 39% say that allowing an **upgrade at their expense** makes the offer better (31% that it does not change the offer, 18% that it is worse).
  - This has limited cost to Enbridge Gas (administration only), and could enhance the offer for some customers, propose to include in the offer.
- 59% of customers think that **energy costs will go up**, 12% think they will stay the same, and 10% think they will go down.
  - Customers indicate that they **would like a bill guarantee** over an extended period. Administratively, it may be better to incorporate this in an upfront payment that compensates given a range of scenarios.
- 71% of customers are clear that they should be **informed about energy efficiency upgrades** and/or that the offer should **include top-ups with higher incentives** for these.
  - Given the support, the offer should include, at a minimum information about energy efficiency programs.

Q If this project were happening in your area, based on this offer, how likely would you be to agree to participate and disconnect?
[asked of all respondents, n=2,000]



Offer Delivery

- In terms of offer delivery, most customers felt that a reputable contractor should deliver the services.
- Requests for Information (RFI) for this work will offer additional insights on delivering the offer.



IRP Technical Working Group

Meeting #54

ENBRIDGE®

June 4, 2025

Agenda

Agenda Item	Purpose	Time Allotted	Lead(s)
Opening Remarks / Preliminary matters	Inform	5 mins	Michael Parkes
Framework Review	Discussion	40 mins	Michael Parkes
TWG Report Comments	Discussion	5 mins	Michael Parkes
System Pruning Draft Approach Feedback	Discussion	20 mins	Catherine McCowan
IRP Pilot Draft Workplan Feedback	Discussion	50 mins	Eric Buan

System Pruning Approach

Highlights

- Enbridge is looking for TWG support for the approach
  - Discussion points are documented throughout in the approach, Some will be explored through execution (e.g. delivery, incentives) and documented in the final report
  - The approach is expected to evolve; updates will be provided to the TWG.
- Jurisdictional scan
  - Jurisdictional scan was not available through the pilot development, but DNV participated in the TWG and provided guidance that the approach was generally aligned with what they were finding, note that the Ontario context is different to that of some of the jurisdictions in terms of the drivers for system pruning.
  - The following areas are aligned with Jurisdictional Scan:
    - Selection criteria – leak prone pipes, small streets & individual customer, higher facility replacement cost per customer
    - Customer offer – addresses concerns about up-front costs
    - Customer communications – in-person, website, email, mail and public meeting to provide specific and general knowledge
    - Customer support – target areas where customers are more supportive
    - Evaluation – emphasis on tracking of customer reaction to gas and electric options, offer elements; role of general contractor in tracking customer reaction
- There will be two pilots:
  - The first will be a street with ~10 customers; the second will be ~10 individual customers spread over a region; one of these will be targeted to be a commercial customer
  - These may change based on customer response to the pilots, but the goal will be to get some diversity in terms of initial sentiment, number of appliances.

Highlights

- Selection criteria and process
  - Initiated as dead-end mains and individual services requiring replacement with system renewal capital
  - Layered in community response to the initial offer (based on Customer Research) and facility replacement cost (based on Financial Comparison).
  - Based on customer response to the offer, criteria may be relaxed to get viable candidates – the selection process will be documented in the final report, including the similarity of the pilot candidates to candidates in general
- Customer Offer
  - Labour and materials to replace all gas equipment and appliances and make any required upgrades to the electrical service and panel
  - The customer will be permitted to make upgrades to appliances and equipment at their own cost
  - The customer will be offered an energy assessment that will provide guidance how they can improve the energy efficiency of their homes and available rebates. If available in the market this will include guidance on expected changes to energy usage and bills. If the customer chooses, these improvements can be executed at their expense when the conversion to electricity occurs and overseen by the general contractor.
  - If the work is overseen by Enbridge's general contractor, a warranty will be provided on the equipment and work (dependent on Enbridge's ability to source this in the general contractor market).
  - An additional incentive that will cover unforeseen extras such as time away from work and small repairs.

Review Timeline

- TWG written comments to Enbridge – June 6th
- Revised draft to TWG – June 18th
- Confirm endorsement – June 25th

IRP Technical Working Group

Meeting #55

ENBRIDGE®

June 25, 2025

Agenda

Agenda Item	Purpose	Time Allotted	Lead(s)
Opening Remarks / Preliminary matters	Inform	10 mins	Michael Parkes
System Pruning – review comments	Discussion	30 mins	Catherine McCowan
IRP Incentive	Discussion	40 mins	Rob Goodreau
IRP Assessment – ETEE/DR Model	Discussion	40 mins	Whitney Wong, Eric Buan

System Pruning

Addressing TWG Feedback

- Jay Sheppard – with input from Mike Parkes, Chris Neme, Enbridge Gas (p.1)
  - *"This approach has been developed in consultation with the TWG, and Enbridge Gas has determined which of their suggestions it will implement in the pilot. The TWG has not formally approved the proposal but supports proceeding with it as a reasonable initial approach, subject to ongoing review and further input as the pilot is implemented and lessons are learned. Consistent with the Settlement Agreement, costs for the System Pruning Pilot have been tracked, and will continue to be tracked, in the IRP System Pruning Deferral Account for later recovery."*
- Mike Parkes – bringing together Mike's language and comments from Dwayne & Chris (p. 5, 20)
  - *"As they arise during the pilot, Enbridge Gas and TWG will identify policy issues that would need to be resolved for system pruning to be implemented on a larger scale. For example, the pilot may inform considerations around obligation to serve when there are holdouts on a street. System Pruning would benefit from clarity about the Policy Objective that it fulfils. Whereas TWG members have indicated that the main driver is reduction of stranded asset risk or lower cost, the Jurisdictional Scan reflected policy drivers that were linked to climate change and social benefits. It is likely that other issues will be identified for documentation as the pilot progresses."*
- Dwayne Quinn
  - Pruning the middle of a pipeline fed from both ends (p.5)
    - Agree and included as footnote shared June 18, as we agreed early on in the TWG meetings that we would limit candidates to dead legs so we did not need to do the hydraulics on each main leg to determine if it could be part of the pilot.
  - The driver for Pruning is Stranded Asset Risk (p.20)
    - See above
- Tammy Kuiken – supportive of the approach provided other members' concerns are addressed.

Addressing TWG Feedback

- Chris Neme
  - Will the pilot inform anything about policy? (p. 2 & p. 20)
    - See changed wording above.
    - Expect to catalogue results of pilot that we encounter that may inform policy consideration
  - Will we pay for the customer's electrical service upgrade (p.3)
    - It was our understanding based on what was shared by Board Staff that the neighbourhood costs would be borne by the LDC but the service costs would be borne by the customer. The following paragraph was added:
    - *"There is uncertainty as to whether the cost of the electrical service upgrade (if required) would be borne by the LDC or the customer. This analysis assumes that it is borne by the customer and, because of the age of the homes in the population, most conversions include the $3,000 noted in Table 14. This will be explored with the LDC as implementation proceeds and may reduce by $3,000 the conversion cost per customer if it is determined that this cost must be borne by the LDC."*
  - Language for describing appliance alternatives (p.8) – replace "appliances that are similar" with *"efficient appliances with comparable features and functionality"*
    - We agree with your language and have adopted it throughout
  - Customer feedback about reliability of the electrical system (p.11)
    - The purpose of customer research is to understand what customers think and how it informs their decision making. The general contractor will provide education to customers so that they are able to make informed decisions.
    - The point of including it in the report is to highlight that it is an area that will require special focus when talking to customers. Many customers, do not perceive a current role of the electrical distribution system in the reliability of their heating system - either because they have a backup generator that is fueled by natural gas or because they have a fireplace that provides some heat in a power outage.

Addressing TWG Feedback

- Chris Neme cont'd
  - Customer Benefits (p.16)
    - Suggest adding the following words *"...customer utility bills, noting that there may be other customer costs and benefits that are harder to quantify."*
  - Table 6 (p.21)
    - The figures in Table 6 do not include replacements where it was only an AMP Fitting Replacement – these are for full service relays.
  - Assumption for cost of a service abandonment (p.22-23)
    - *"Based on 2024 averages, the cost for a Cut-Off at Main ("COAM") is a little over $3500 for rural services and a little under $6,000 for urban services. The connection to the main is usually in the public right of way and, in an urban environment, this can involve complex permitting, traffic planning, and construction activity. Whereas service replacements are often part of a project and concentrated in a specific geography, COAM are driven by customer requests – demolition, alteration – and may be more scattered. The context for the System Pruning Pilot is different yet again. While the individual customers that participate in the pilot will require a COAM, it may be possible to reduce the number of cuts on a street if multiple customers participate in the pilot. With these variable factors, the cost to abandon the gas service was assumed to be 50% of the cost to replace it – this is a little lower than historical average for rural services and significantly lower than historical average for the urban services. Recognizing the range of potential costs for the service abandonments, a sensitivity analysis was completed in which the costs were halved and doubled – taking the service abandonment cost from $1,000-$1,500 up to $4,000-$6,000."*

Next Steps

- June 27 EGI to send final System Pruning Pilot approach to TWG (following today's discussion)
- July 4 2024 IRP Annual Report will be filed with Phase 3 interrogatory responses with System Pruning Pilot approach as Appendix

IRP Technical Working Group

Meeting #57

ENBRIDGE®

July 30, 2025

Agenda

Agenda Item	Purpose	Time Allotted	Lead(s)
Opening Remarks / Preliminary matters	Inform	5 mins	Michael Parkes
IRP Pilots Update – SLH and System Pruning	Inform	15 mins	Eric Buan / Whitney Wong / Gesiena Antuma
System Pruning Jurisdictional Scan	Discussion	15 mins	DNV
IRP Evaluation - Update on evaluation status - DCF+ results and interpretation - DCF+ Update	Discussion	55 mins	Helen Tong / Margarita Suarez / Brandon So
Framework Review	Discussion	55 mins	Michael Parkes

IRP Pilots Update

Southern Lake Huron and System Pruning

System Pruning Update

Item	Update
Contractor Engagement	• RFP for contractor was issued June 27, responses are due back Aug 8
Customer Engagement	• Customer survey to establish preliminary interest in proceeding has been drafted and shared • Seeking written TWG feedback by Friday August 8th
DNV Jurisdictional Scan	• Discussion on finalization of report

IRP Technical Working Group

Meeting #61

ENBRIDGE

December 3, 2025

Agenda

Agenda Item	Purpose	Time Allotted	Lead(s)
Opening Remarks / Preliminary Matters	Inform	5 mins	Michael Parkes
System Pruning Project Update	Inform / Input	55 mins	Catherine McCowan / Gesiena Antuma

System Pruning Pilot

Implementation Update

Item	Update
Contractor Engagement	• Contractor selected and contract signed • Completing onboarding steps • Finalize customer engagement process (December) • Contractor engagement with customers (Q1 2026)
Customer Engagement	• Incorporated TWG feedback into pre-screen form • Sent out direct mail via courier and emails • Pre-screen results informed selection of candidates for handover to contractor for 1:1 engagement on the Customer Offer

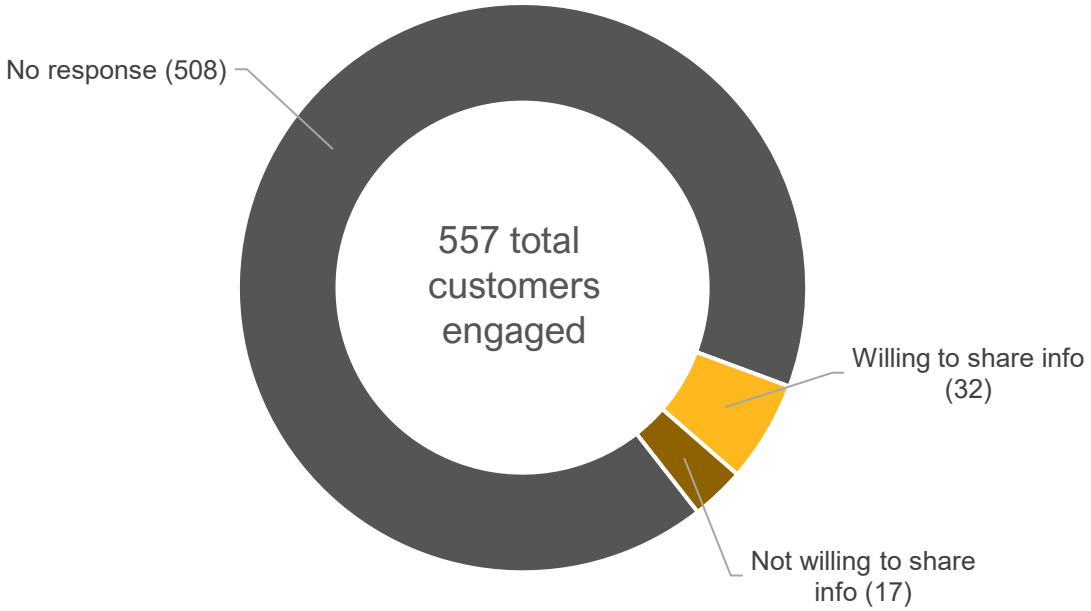
Customer Interest Form Results
Prepared by Customer & Market Insights

Pre-screen Form Results

- Of the 557 customers who were sent a direct mail via courier (of which 409 also received emails) 49 responses to the pre-screen form were received
- ***Note:*** *Form results cannot be extrapolated to the entire population of customers who received the invitation to express interest*

Responses to Pre-Screen Form

(n=49, respondents who answered this section of the form)



Pilot Category	Single Service		Street Level	
	Willing to share contact info	Not willing to share contact info (or no answer)	Willing to share contact info	Not willing to share contact info (or no answer)
Definitely likely to participate	6	0	13	3
Somewhat likely to participate	3	2	8	3
Not very likely to participate	0	2	1	1
Not at all likely to participate	0	3	0	2
Don't Know	0	0	1	1
No response	508			

Motivations and Barriers to Participation

Motivations for Participating

- **Environmental Benefits** – Reduce emissions, support sustainability, improve indoor air quality.
- **Cost Considerations** – Expectation of long-term savings and cost stability.
- **Efficiency & Upgrading** – Electric systems perceived as more efficient; appliances aging and due for replacement; improved comfort and reduce servicing needs.
- **Technology & Future Orientation** – Positive attitude toward innovation and electric solutions.
- **Safety & Health** – Avoid gas leaks, reduce noise, improve home safety.

Barriers for Participating

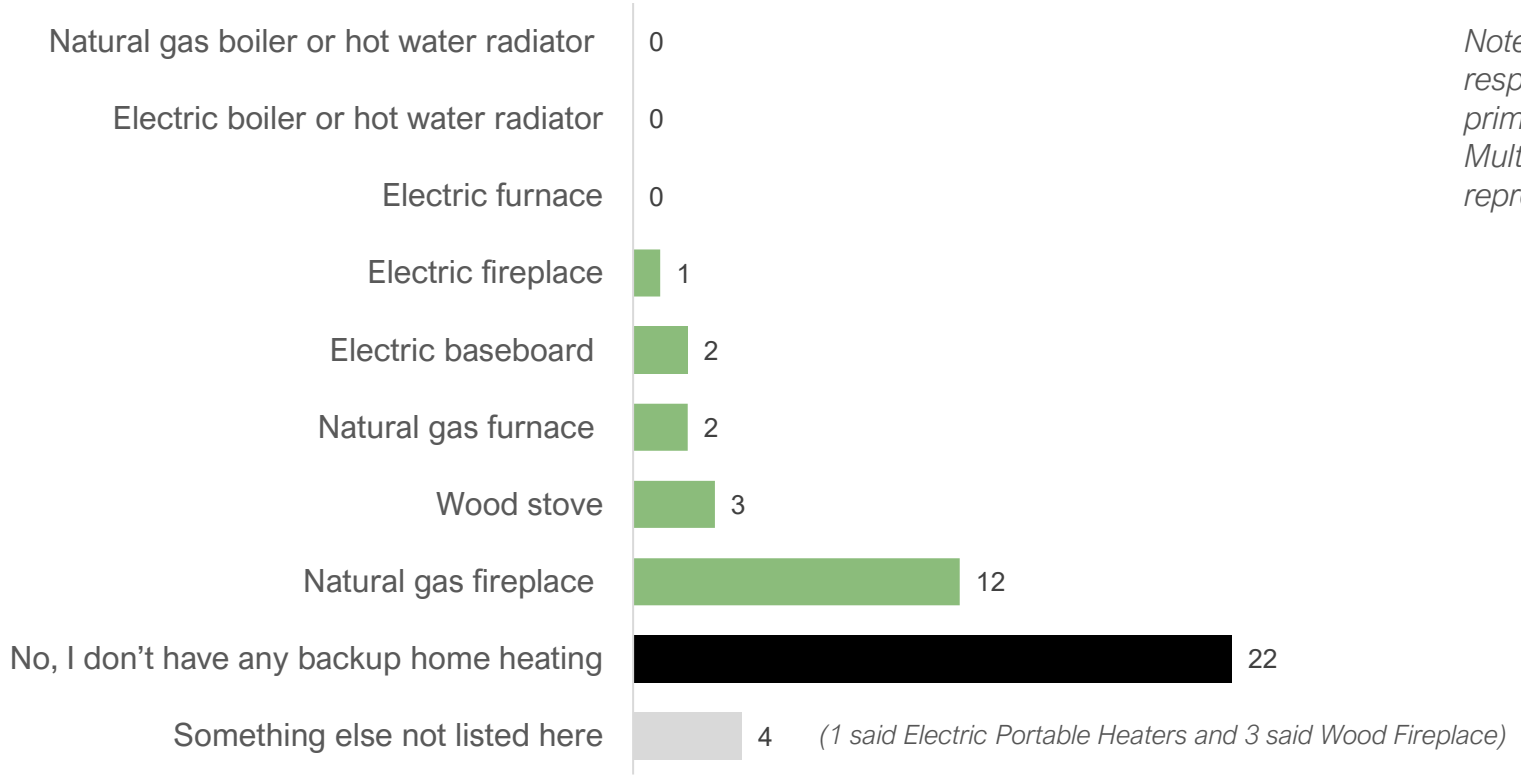
- **Cost & Billing Concerns** – Worries about high electricity bills and time-of-use pricing; perception that electric systems may be more expensive overall.
- **Reliability & Backup** – Preference for natural gas as a dependable backup during outages.
- **Preference for Gas** – Strong attachment to gas for cooking, heating, fireplaces, and BBQ.
- **Sunk Investments** – Reluctance to switch due to existing investments in their natural gas equipment.
- **Trust & Confidence** – Concerns about reliability and performance of electric systems.

Home Heating Systems: Primary and Backup

- Nearly all respondents (38 of 41) who answered this section of the form, reported using a natural gas furnace for home heating. The remaining three reported an air source heat pump, an electric furnace, and a natural gas boiler/hot water radiator.

Types of Backup Home Heating Systems

(n=41, respondents who answered this section of the form)



(1 said Electric Portable Heaters and 3 said Wood Fireplace)

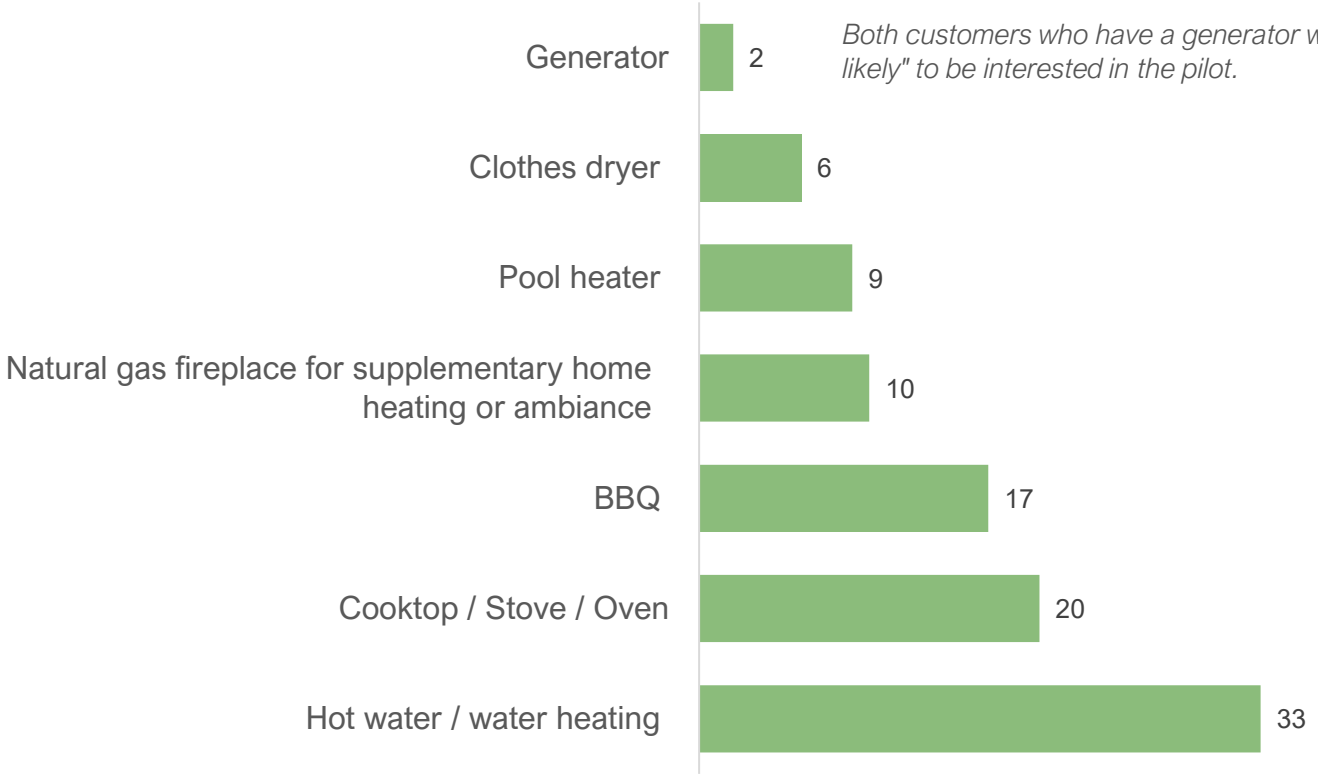
Note: Base sizes vary depending on respondents' answers to Q4 ("How do you primarily generate heat in your home?"). Multiple responses were allowed; counts represent mentions, not unique respondents.

- *The majority of respondents do not have any backup home heating; among those who do, natural gas fireplaces are most common*

Other Natural Gas Usage in the Home

Number of Appliances Using Natural Gas

(n=43, respondents who answered this section of the form)



Both customers who have a generator were "not very likely" to be interested in the pilot.

Note: Respondents could select multiple options; counts represent mentions, not unique respondents.

- *Natural gas home heating is the top natural gas use, followed by water heating, cooking and BBQs*

Respondent Profile

NUMBER OF PEOPLE IN HOUSEHOLD	
One	10% (n=5)
Two	22% (n=11)
Three	22% (n=11)
Four	14% (n=7)
Five or More	6% (n=3)
NA/Prefer not to answer	24% (n=12)

AGE	
Between 18 and 44	10% (n=5)
45 – 64	27% (n=13)
65 – 74	27% (n=13)
75 years +	10% (n=5)
NA/Prefer not to answer	27% (n=13)

HOUSEHOLD INCOME	
$39,999 or less	4% (n=2)
$40,000 to $59,999	8% (n=4)
$60,000 to $79,999	0% (n=0)
$80,000 to $99,999	8% (n=4)
$100,000 to $124,999	4% (n=2)
$125,000 to $149,999	4% (n=2)
$150,000 and Over	12% (n=6)
NA/Prefer not to answer	59% (n=29)

System Pruning Candidates

Approach to developing candidate pool for outreach

Key criteria and analysis that informed the candidate customer list:

Asset base (Jan 2025)	• Identified gas mains at the end of networks and individual services that will require replacement in coming years for integrity reasons • Approx. ~200,000 customers
Customer Research (Feb & April 2025)	• Qualitative (focus groups) and quantitative (surveys) customer research conducted on a sample of customers in the asset base to understand attitudes and expectations related to System Pruning • Informed development of System Pruning Approach
Preliminary Financial Analysis (May 2025)	• To understand the expected cost, on a preliminary basis, to replace the mains and services for the customer relative to the cost to convert the customer to electricity and abandon gas facilities
Candidate Customers (Oct 2025)	• Apply additional criteria to the asset base, informed by customer research and preliminary financial analysis to narrow down customer list to be targeted • Customers where the expected cost to replace the mains and services >$30K • Customers in communities where the positive reaction based on the quantitative survey was >40% • 557 customers
Pre-Screen Form (Oct/Nov 2025)	• Direct mail sent out to the 557 customers (409 of which received emails as well) • Provided customers with high level offer details and link to a voluntary interest form • Customers asked to express interest by Nov 10 through pre-screen interest form

Criteria in selecting pilot candidates

- Reflect customer response from the pre-screen form and final jurisdictional scan findings
- Maximize the likelihood that the full system pruning process would be tested to provide learnings on conversion costs and the process
- Potential to realize avoided facility cost where customers convert to non-natural gas appliances / equipment
- Diversity of residential candidate customers
- Operational efficiency in the delivery of the work by the contractor

Individual Service Pilot – Residential

Criteria for respondents as an individual service candidate:

- Last customer on the dead-end main – disconnection would allow for decommissioning of their service and associated main to their home
- Reduction in replacement costs when the main on the street is later replaced

Propose to proceed with 6 residential customers to next implementation step for individual service pilot (table below).

- Only 6 respondents had a sentiment of "Definitely Likely" - proceeding with these 6 maximizes likelihood of testing full conversion process
- Appliances beyond natural gas space and water heating represented
- Urban communities with Picton as a smaller community represented
- Range of customer age, house size and year built

Breakdown of candidates:

Interest	Community	Appliances (1)	Backup Heating	Customer Age Range	Income Level	House Size	Build Year	LDC
Definitely Likely	Etobicoke	GF / ASHP / WH /BBQ / P	Natural Gas Furnace	50 - 59	$150K and over	1500-2500	1957	Toronto Hydro
Definitely Likely	Scarborough	GF	None	30 – 39	Not answered	<1500	1958	Toronto Hydro
Definitely Likely	Toronto	GF / WH / F	Natural Gas Fireplace	60 – 69	$100 - $125K	1500-2500	1960	Toronto Hydro
Definitely Likely	Oakville	GF / WH	None	70 – 79	Not answered	>2500	1981	Oakville Hydro
Definitely Likely	Mississauga	GF / WH	None	Not answered	Not answered	1500-2500	1980	Alectra
Definitely Likely	Picton	GF / S	Electric Fireplace	70 – 79	Not answered	<1500	1948	HONI

(1) Appliance Legend

GF – Natural Gas Furnace ASHP – Air Source Heat Pump P – Natural Gas Pool Heater S – Natural Gas Stove/Oven WH – Natural Gas Water Heater BBQ – Natural Gas BBQ D – Natural Gas Dryer F – Natural Gas Fireplace

Individual Service Pilot – Commercial

- To identify a commercial customer for targeting, leveraged the list of leak-prone services that had been identified by Integrity (e.g. isolated steel headers, farm taps with known poor condition)
- Similar to residential criteria, layered on the projected cost of the work to remediate the leak-prone service
  - None of the commercial services identified were at the end of a main which would allow the main to be abandoned as well in event they convert from natural gas
- Only one commercial customer identified with a service replacement cost > $30K
  - Note that this is consistent with the financial bar for residential customers, but cost to convert a commercial customer expected to be higher
- Not sufficient candidacy to proceed with further implementation steps

Commercial Customer Engagement Summary

- Conducted outreach through DSM Commercial team with the identified commercial customer for the individual service pilot. Engaged to seek decision maker to introduce the pilot and determine their interest in proceeding to next implementation step.
- Determined that the customer's intent was to eventually redevelop the land but that the plan was uncertain due to the real estate market – they would therefore not be able to make decisions for 2026

Street Level Pilot

Pre-screen survey results:

- No street with 10 or less customers had more than one respondent to the pre-screen form where they were both willing to have their information shared with the contractor to proceed to the next step
- Not sufficient interest to proceed with further implementation of a street level pilot

This finding is aligned with the jurisdictional scan (Aug 2025) where system pruning projects averaged less than 2 customers

- California: 88 projects with 105 customers
- New York: 14 projects with 24 customers

System Pruning Pilot Direct Mailer

All Electric Pilot Project

Interested in going all electric?

Selected participants will have all their natural gas appliances and equipment replaced with electric versions



ENBRIDGE®

All Electric Pilot Project

A fully electrified home, at no cost to you



Dear <customer name>

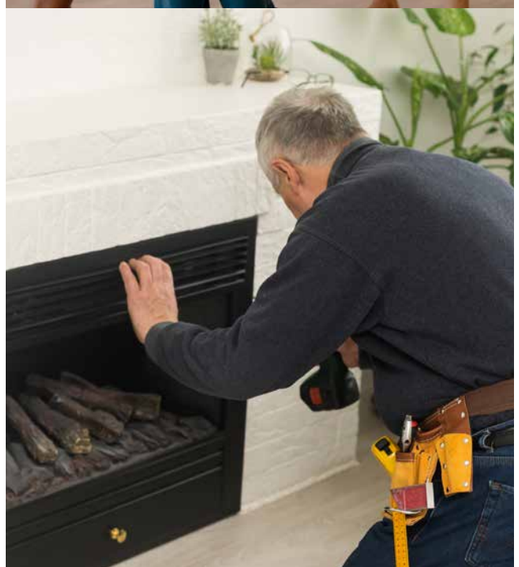
Enbridge Gas is seeking 20 homes to convert from natural gas to all electric—free of charge.* We are asking you to fill out a brief interest form to help us select the eligible neighbourhood and homes for this pilot project.

If selected and you choose to participate, all of your natural gas appliances and equipment will be replaced with new, efficient electric versions. See the list below for examples:

Natural gas appliances	Popular replacements
Furnace	Electric heat pump
Range	Electric range
Water heater	Electric heat pump water heater
Fireplace	Electric fireplace
Barbecue	Propane barbecue

The natural gas appliances and electric replacements listed above are provided for general informational purposes only.





Why is Enbridge Gas doing this?

Your neighbourhood has been identified as requiring future investment in its natural gas infrastructure. This pilot project is exploring whether converting homes to electricity is potentially less expensive than future natural gas infrastructure investment.

Do I have a choice?

Yes. If your street is confirmed for the pilot, it's completely up to you whether you choose to participate in this pilot project. We encourage you to fill out the interest form whether you're interested or not to help inform our decision. We value your feedback.

Enbridge Gas is working with a designated third-party delivery agent and their approved contractor

Our designated third-party delivery agent will replace your natural gas appliances with electric ones (or other alternatives). They'll provide hands-on support throughout the entire process for a seamless transition.

Enbridge Gas will:

Replace all of your natural gas appliances.

Install new electric versions with warranty.

Include a comprehensive energy assessment.

Work with trusted, professional contractors.

Provide guidance to address your needs or questions.

All Electric Pilot Project



We want to hear from you

Please fill out a quick interest form by Nov. 10, 2025 at

enbridgegas.com/allelectric
or scan the QR code.

Scan me

All feedback is valuable.

We value your opinion and will use your feedback to help gauge public interest and to choose the neighbourhoods selected for the pilot project.

* Terms and conditions apply. All Electric Pilot Project provides access to the replacement of natural gas appliances and equipment with electric versions at no cost. This expression of interest is available exclusively to the individual(s) addressed in this communication. It is non-transferable and may not be shared, forwarded or redistributed. This expression of interest is intended solely for invited participants.

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System Pruning Pilot Email

ENBRIDGE

All Electric Pilot Project

Convert to a fully electrified home at no cost to you

Enbridge Gas is seeking 20 homes to convert from natural gas to all electric—free of charge.* We are asking you to fill out a brief interest form to help us select the eligible neighbourhood and homes for this pilot project. Please let us know of your interest. We value your feedback.

Let us know



If selected and you choose to participate, Enbridge Gas will:

- Replace all of your natural gas appliances.
- Install new, efficient electric versions with warranty.
- Include a comprehensive energy assessment.
- Work with trusted, professional contractors.
- Provide guidance to address your needs or questions.

Natural gas appliances	Popular replacements
Furnace	Electric heat pump
Range	Electric range
Water heater	Electric heat pump water heater
Fireplace	Electric fireplace
Barbecue	Propane barbecue

Why is Enbridge Gas doing this?

Your neighbourhood has been identified as requiring future investment in its natural gas infrastructure.

This pilot project is exploring whether converting homes to electricity is potentially less expensive than future natural gas infrastructure investment.

Do I have a choice?

Yes. If your home is selected, it's completely up to you whether you choose to participate in this pilot project.

Yes or no, we'd like to know!

We value your opinion and will use your feedback to help gauge public interest and to choose the neighbourhoods selected for the pilot project.

To learn more about the project and fill out the interest form, visit: enbridgegas.com/allelectric

Please complete the interest form by **Nov. 10, 2025.**

ENBRIDGE

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System Pruning Pilot Webpage

All Electric Pilot Project

Ready to go all electric?

Enbridge Gas is seeking 20 homes to convert from natural gas to all electric—free of charge.* We are asking you to fill out a brief interest form to help us select the eligible neighbourhood and homes for this pilot project.

If selected and you choose to participate, you will have all of your natural gas equipment and appliances replaced with new, efficient electric versions.

Interested? Yes or no, we want to know!

How does this pilot project work?



Participation in the All Electric Pilot Project is by invitation only.
Only those contacted directly by Enbridge Gas are eligible.

If selected and you choose to participate, Enbridge Gas will:

- Replace all of your natural gas appliances.
- Install new, efficient electric versions with warranty.
- Include a comprehensive energy assessment.
- Work with trusted, professional contractors.
- Provide guidance to address your needs or questions.



Examples of common natural gas appliances and their popular electric or non-natural gas replacements.

Natural gas appliances	Popular replacements
Furnace	Electric heat pump
Range	Electric range
Water heater	Electric heat pump water heater
Fireplace	Electric fireplace
Barbecue	Propane barbecue

The natural gas appliances and electric replacements listed above are provided for general informational purposes only. Enbridge Gas will work with participating customers to do a full assessment of their existing natural gas appliances and equipment to find the right electric fit to ensure that this transition is seamless.

How it works

1. **Interest period**
   Complete the interest form by Nov. 10, 2025, to tell us if you're interested in the pilot project. There's no commitment required at this stage.
2. **Candidate selection**
   If your home is selected, we'll invite you to chat with a trusted contractor to review next steps.
3. **Meet our contractor**
   To ensure a seamless transition, a qualified contractor will walk you through the project and explain the work involved in detail. Here, you'll have the opportunity to ask any questions you may have.
4. **Customized plan**
   Our contractor will perform a home energy assessment then provide you with a custom plan outlining all the necessary conversion measures that will be covered. The plan may include additional options, where rebates are available outside of this pilot project, such as adding insulation, upgrading windows and other ways to help you save energy.†
5. **Offer acceptance**
   You will receive an offer from Enbridge Gas. The offer will detail the work that is covered under the pilot project, plus any costs for additional work you may have decided to include. Please note that Enbridge Gas will not cover items that are outside of the scope of the pilot project. You will need to cover the costs for any additional work.
6. **Work begins**
   During this time, your home's natural gas appliances will be removed and replaced with new, efficient electric versions. Once the work is finished, your natural gas service will be decommissioned.
7. **Check in**
   After your home is converted, we'll follow up to make sure everything's working well and invite you to share feedback about your experience.

Why is Enbridge Gas doing this?
Your neighbourhood has been identified as requiring future investment in its natural gas infrastructure. This pilot project is exploring whether converting your home to electricity is potentially less expensive than future natural gas infrastructure investment.

All feedback is valuable

We value your opinion and will use your feedback to help gauge public interest and and to choose the neighbourhoods selected for the pilot project. Please complete the interest form **by Nov. 10, 2025**.

Complete interest form

Frequently asked questions

- Can anyone sign up for the All Electric Pilot Project?
- Do I have a choice whether I participate?
- Will it cost me anything to participate?
- Will I be disconnected from natural gas lines?
- Can I reconnect to natural gas in the future?
- Will my energy bills go up after I convert?
- Will Enbridge Gas cover any expenses incurred for time off work or minor repairs?

Still have questions?

Please contact our project team:

Email: allelectric@enbridgegas.com

*Terms and conditions apply. All Electric Pilot Project provides access to the replacement of natural gas appliances and equipment with electric versions at no cost. This expression of interest is available exclusively to the individual(s) addressed in this communication. It is non-transferable and may not be shared, forwarded or redistributed. This expression of interest is intended solely for invited participants.

†Any references to energy saving are intended to provide information regarding potential savings and reductions under typical usage conditions. Enbridge Gas does not guarantee that savings or reductions will occur in any individual case. Variables that may impact savings or reductions include specific circumstances related to the participant's environment, installation, maintenance and operations practices, changes in energy prices, weather and local climate conditions, and user behaviour and changes in usage patterns.

Can anyone sign up for the All Electric Pilot Project?

No. Eligibility is limited to customers living on the selected street or specific homes identified for the pilot. If you have been contacted personally about the pilot project, you are within our area of interest. Enbridge Gas will determine homes eligible for the pilot project based on the responses to the interest form.

Do I have a choice whether I participate?

Yes. It’s completely up to you whether you choose to participate in this pilot project. Participation is not guaranteed. Enbridge Gas will determine pilot project eligibility based on the responses to the interest form.

Will it cost me anything to participate?

If selected and you agree to the offer, Enbridge Gas will cover the conversion costs for disconnecting from natural gas and installing new, efficient electric appliances.

Will I be disconnected from natural gas lines?

Yes. If selected and you agree to the offer, your home will be permanently disconnected from the natural gas distribution system. This means the natural gas line serving your home will be decommissioned.

Can I reconnect to natural gas in the future?

If you decide to reconnect to natural gas after participating, it will be treated as a new connection. You will be responsible for paying all reconnection fees, as well as the purchase and installation of any natural gas appliances you want to use.

Will my energy bills go up after I convert?

Energy bill outcomes can vary by pilot location, local utility rates, your home’s efficiency, how you use energy, weather and future policies/inflation. Once the pilot location is confirmed and we complete your in-home energy assessment, we will estimate your expected change in energy use and the likely impact on your bills. An upfront incentive designed to help manage potential bill increases may be offered at this time.

Will Enbridge Gas cover any expenses incurred for time off work or minor repairs?

During the in-home visit, discuss your circumstances with the qualified general contractor. They will document what’s needed. Eligible items and the approved amount will be confirmed in your written offer before work begins.

Examples of “minor repairs” may include patching and finishing small wall or ceiling openings from vent or equipment removal, sealing old penetrations and light carpentry or paint touch-ups related to the conversion. Major renovations or unrelated improvements are not included.

System Pruning Pilot – Objectives & Key Elements

Presented January 2025 for Input from the TWG Subgroup

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January 16, 2025

Background & Meeting Objectives

Settlement Agreement

The Parties have agreed that Enbridge Gas will develop its approach to system pruning in consultation with the IRP Technical Working Group by the end of Q2 of 2025 and begin implementation on one or two pilots by the end of Q1 of 2026.

Meeting Objectives

- Determine the key **elements** of the **approach**
- Discuss initial considerations for each element and gather feedback from sub-committee

Elements of the Approach – for June 2025

- List of Elements for consideration:
  - Pilot Objectives
  - Selection Criteria
  - Customer Incentive
  - Customer Engagement
  - Customer Choice
  - Stakeholder Engagement
  - Program Delivery
  - Implementation Plan

- These elements will be developed in consultation with the TWG Subgroup and shared with the TWG.

Pilot Objectives

- Understand customer perspective on disconnecting from the NG distribution system.
  - What are customer perceptions and how do these drive their decision-making?
- Understand customer reaction to incentives and whether they can be incented to disconnect from the system in a way that is economic relative to the replacement of the mains and services.
  - Other than economics, what factors positively or negatively impact customer desire to convert?
- Understand what works and does not work in program delivery
  - In terms of targeting customers, is it more effective to have a broad program at the individual service level or a targeted program at the main section level?
  - RFP and contracting with participating contractor(s)
    - Fair and equitable for contractors that have the skills to guide customers through the process of converting to electric appliances & equipment
  - Initial and ongoing communication to customers on the pilot systems
    - How does Enbridge establish the legitimacy of the contractors and the process?
  - Contractor payment structure to drive good customer experience and low cost of delivery.

Selection Criteria

Assumptions:

- Pilot will be based on conversion to grid electricity
- To manage cost, and impact to LDC, the number of customers converted will be small (fewer than 20).
- Pilot customers will be on individual services or ends of mains so as not to affect the network hydraulics.
- Pilot assets will be those that would be replaced as part of System Renewal capital
- Pilot(s) should be representative of other customers and assets in the system

Considerations:

- Are there other factors/system data (i.e. temperature, demographic, building type) that should be considered either as a criteria in choosing the pilot or as something to be tested during the pilot?
- Are there social factors that should be considered?

- If many assets and customers meet the agreed criteria, Enbridge will select pilot(s) that conform to the criteria and are representative of the system as a whole.

Customer Incentive

Assumptions:

- The cost of the main & service replacement will be compared to the cost of the customer incentives & abandonments but, for the pilot, it is not necessary that the cost of the customer incentives is less than the cost of the main and service replacement.

Considerations:

- Should the offer eliminate any price disadvantage to a customer who converts to electricity?
  - If yes, what is the price point for the appliance conversion?
    - Replace with similar quality? Or decide on a standard replacement package and customer pays if they want better quality?
  - If no, and the offer doesn't need to fully reimburse, what is it based on?
    - Is it the value that breaks even between the full replacement of the mains and services vs the customer incentive and abandonment of mains and services.
- How do we treat the price of the commodity – role of carbon price and subsidies.
- How do we consider available incentives?

Financial Analysis to be shared with the TWG Subgroup:

- Cost for customer to heat with a heat pump;
- Cost to replace customer equipment/appliances
- Cost to replace mains and services
- Cost to complete main and service abandonments

Customer Engagement

Assumptions:

- Work will be done by Innovative Research Group, and questions will be reviewed by the TWG Subgroup ahead of time with an opportunity for input.

Considerations:

- We anticipate two rounds of customer engagement leading up to the pilot:
  - The first, will be general and will use focus groups to understand what customers will want to know when making a decision to disconnect from the natural gas system.
  - The second will be more focused and will present customers with a hypothetical alternative to receive an incentive to disconnect from the gas system or continue to be a natural gas customer.
- Are there other things that we should test leading up to June?

Customer Choice

Assumptions:

- Customers will not be incented to convert to appliances & equipment that are higher in overall emissions.

Considerations:

- If one or more customers chooses not to disconnect, should we:
  - Replace the mains and services instead of disconnecting the customers or,
  - Allow some customers to disconnect and replace whatever portion of the mains and services is still required?
- If a home or business owner chooses to disconnect, can they later reconnect? If a pruned home or business changes hands, can the new owner connect to the natural gas system?
- How much support can/should customers get in guiding them through the conversion of appliances/equipment and in recovering any rebates or incentives?

Stakeholder Engagement

- Stakeholder Engagement will be done once specific location(s) are identified for the pilot(s) and could include Municipalities, LDC's, Indigenous groups, residents' associations, condo boards, etc.

Program Delivery

- Enbridge plans to issue an RFP to contractors that can work directly with customers to identify and install suitable replacement equipment and appliances.
  - Contractors must indicate what geographies they are able to provide service for,
  - Contractors must handle all the leads provided for their given geography,
  - Contractors must provide a unit rate for customer lead management and conversion with any caveats and extras that could be incurred as well as an estimate of how often they are likely to occur.
- Contractors must be able to meet Enbridge's Supply Chain Management requirements.
- Enbridge will select one contractor for any given geography.

Implementation Plan

- Pilot(s) location and rationale
- Perform Stakeholder & Customer Engagement
- Engage Contractor
- Complete customer conversions
- Complete service cut-offs and main abandonments
- Prepare Pilot Findings

System Pruning Pilot

Planned for Presentation on February 13, 2025 for Input from the TWG Subgroup

Note:

- *Feb 13 Subgroup TWG Meeting was cancelled due to Provincial Election. Content provided for awareness, and will be reviewed in person at the earliest subgroup meeting in March*
- *Feb 26 full TWG Meeting was also cancelled. There are references to content that was to be shared. Content to be reviewed as early as possible in March with the full TWG.*

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February 13, 2025

For Discussion and Agreement today

- Housekeeping
  - Booking meetings post-March
- Pilot Objectives – updated based on feedback
  - Feedback on approach to engagement with IESO and LDC
- Selection Criteria – updated based on feedback
  - Sample of the mains & services that could be selected
- Customer Research Approach
  - Question Guide for Focus Groups

Housekeeping

- Proposing a cadence of every 4th Thursday:
  - April 10
  - May 8
  - June 5
  - July 3 (if required)

Pilot Objectives

To be shared with full TWG February 26th (new date TBD)

**Added following input from TWG Subgroup*

- Understand customer perspective on disconnecting from the NG distribution system.
  - What are customer perceptions and how do these drive their decision-making?
- Understand customer reaction to incentives and whether they can be incented to disconnect from the system in a way that is economic relative to the replacement of the mains and services.
  - Other than economics, what factors positively or negatively impact customer desire to convert?
  - *The goal is to learn and document what the factors are – not to "force" a customer off the system.**
  - *Customers will not be incented to move to a solution with higher overall emissions**
- *Understand what data or other information is relevant to collect for the IESO and LDC in the pilot area**
- Understand what works and does not work in program delivery
  - In terms of targeting customers, is it more effective to have a broad program at the individual service level or a targeted program at the main section level?
  - RFP and contracting with participating contractor(s)
    - Fair and equitable for contractors that have the skills to guide customers through the process of converting to electric appliances & equipment
  - Initial and ongoing communication to customers on the pilot systems
    - How does Enbridge establish the legitimacy of the contractors and the process?
  - Contractor payment structure to drive good customer experience and low cost of delivery.
- *Understand what policy and framework elements need to be reconsidered by the Ontario Energy Board if system pruning is to become a broader program.**
  - *This will be on a best-efforts basis. The pilot, being small, is not likely to turn up all policy and framework needs.*

Objective - Engagement with LDC & IESO

- Enbridge will engage with the IESO and 1-2 LDC's ahead of June 2025 to understand what information would be useful to collect through the pilot.
  - Provided the information is available and can be collected without negative impact to timelines, customers, and other pilot objectives, Enbridge will incorporate its collection into the execution of the pilot.
  - Confirm that this is what was intended by OEB Staff in terms of LDC & IESO engagement.

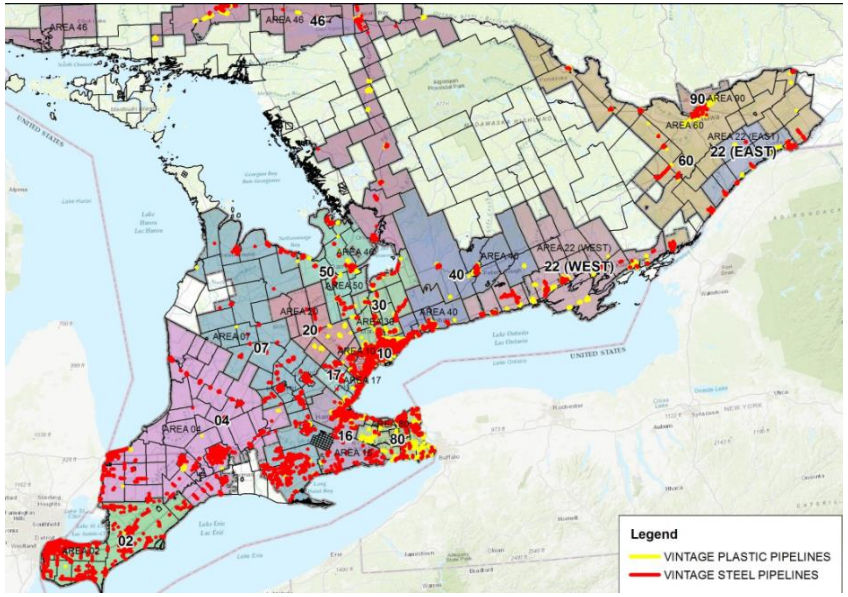
Pilot Selection Criteria

To be shared with full TWG February 26th

**Added following input from TWG Subgroup*

- Cost of customer incentive is offset by the cost of the asset replacement – targeted assets will be part of System Renewal Capital.
- Structured data search will include the following criteria:
  - Dead end legs
    - Vintage Steel
    - Aldyl A
  - *Individual services with:**
    - Farm taps (field verified to require remediation)
    - AMP Fittings (scheduled for replacement 2026 or later)
    - Service extensions (field verified to require remediation)
    - Bulk meters (field verified to require remediation)
- Structured data analysis is reviewed with Operations, Integrity and Asset Management to identify omissions or inclusions.
  - A review of work orders will also confirm that the remediation work has not already been completed or planned for 2025.

Examples from the Selection Criteria









Customer Research

- Innovative Research Group will conduct customer research in two tranches to support development of approach:
  - *Qualitative:* 4 geographically dispersed focus groups, targeting the residential market, to understand customers response this sort of opportunity
  - *Quantitative:* Surveys to follow, with number of surveys dependent on population size

Focus group (planned for week of Feb 24):

- Focus group population:
  - Target residential customers that meet pilot criteria
  - Non-residential customers will have more diverse needs that will be addressed directly if included in the pilot area
  - Surveyed customers will be excluded from the pilot where possible

- Customer research will test:
  - Willingness to convert if the offer is based on equipment and appliances similar to their existing in terms of quality and functionality.
  - Preference on contractor oversight during the process:
    - Should it be turnkey for the customer to installers and Enbridge or
    - Should the customer receive a cheque upon disconnection from the gas distribution system or
    - Something between these extremes
- Customer research results will inform approach and subsequent survey language and may narrow the pool of suitable pilot locations.

Customer Research

Pilot Implementation Phase

- Longitudinal research will be conducted on customers that convert to:
  - Understand the degree to which they view the appliances and equipment that they receive through the pilot as "similar",
  - Understand their satisfaction with the conversion process and the interaction with the contractor,
  - Understand the impact to electricity bills

Feedback & Questions?

System Pruning Pilot

Input from the TWG Subgroup

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March 20, 2025

Topics for Discussion

- Basis for the Customer Offer
  - Seeking input on the basis of the Customer Offer to support Customer Research survey
- Customer Research
  - Innovative Research to attend March 20th TWG Subgroup
  - Review focus group findings
  - Review quantitative survey questions
- Contractor Strategy
  - Seeking input on the description of the services to be provided by the general contractor.
  - Seeking input on companies that should be considered for the RFI
- Customer Engagement
- Implementation approach
  - Seeking input on the approach described

Basis for the Customer Offer

- Wide range of technologies (price, performance) available for customers to convert their equipment and appliances from natural gas to electricity
- Customer offer will aim to provide customers with comparable equipment and similar features:

Appliance	Most common replacement option (subject to review with the homeowner)
Natural Gas Furnace	Cold climate air source heat pump with electric backup
Natural Gas Boiler / Hydronic System	Air to water heat pump with electric backup
Natural Gas Water Heater	Heat pump hot water heater or electric water heater (tank or tankless)
Natural Gas Cooktop / Stove	Induction stove (same number of burners)
Natural Gas Oven	Electric oven
Natural Gas Fireplace	Electric fireplace
Natural Gas Clothes Dryer	Electric clothes dryer
Natural Gas Barbecue	Propane BBQ
Natural Gas Pool heater	Air source heat pump for pool

  - Catalogue of similar appliances to be developed to support the contractors that are delivering the service.
  - Customers can install different technologies or upgrades at their expense
  - Customers will be made aware of rebates that may be available to improve the energy efficiency of the building and lower the heating and cooling requirements.
- In addition to the appliances and equipment, the offer will cover the work to remove the natural gas appliances, equipment, and gas piping from the home, install the electric equipment and appliances, and perform any upgrades to the electrical system in the home.
- Note: Customer Research may provide additional insight and changes in the customer offer

Customer Research

Focus Groups completed Feb 24/25

- Key considerations from focus groups:
  - Some customers wanted to get their own contractor to do the work whereas others wanted a turnkey solution
  - Some customers thought that their energy bills would increase and that an incentive to cover this was warranted
  - Some wanted security over the longer term both in terms of energy costs and extended warranties for equipment
  - Beyond receiving new appliances, some customers thought that an incentive was appropriate for hassle, incidentals, etc.
- These will be tested in the quantitative research

Quantitative Customer Research

- Review survey questions
- Timing of survey - sent via email, beginning March 31st

Contractor Strategy

- Enbridge will issue an RFI to:
  - Develop language around the way that the contractors should engage with customers so that they do not feel pressured either to disconnect or remain on the natural gas distribution system
  - Develop qualification requirements so that the contractors are knowledgeable and able to provide a fair assessment of different technologies and brands as well as energy efficiency measures
  - Gain insights into the role of a general contractor versus the role of trades and installers
  - Consider how the work and payment should be structured to drive the best outcomes for customers at a reasonable price
- Currently, we are thinking that the general contractor will:
  - Respond to all leads in a certain geography
  - Educate the customer on the process, available rebates, costs and benefits related to converting to electricity
  - Educate the customer on measures that can be taken to improve the building efficiency and rebates that are available
  - Educate them in a non-biased manner on the available appliances and equipment that are similar to their existing equipment, the functionality and cost (non-biased with respect to brand or technology)
  - Establish their interest in proceeding and timing for doing so
  - Coordinate with various trades to provide a seamless customer experience as appliances and equipment are exchanged, gas piping is removed, electrical upgrades are completed, and energy efficiency measures are implemented as required
  - Coordinate with Enbridge so that meter and riser can be removed, service cut off at main and main abandonment are completed
- Seeking input on the Contractors that should receive the RFI

Customer Engagement

Customer facing information

- Brochure/Letter that general contractor can leave with the customer
  - What is System Pruning?
  - Why is Enbridge Gas doing this?
  - Do I have to disconnect?
  - How do I learn more
  - Key contacts: General Contractor, Enbridge System Pruning Website, Enbridge Gas email for System Pruning Questions
  - Date that we will need a response from them on whether they will be disconnecting
- Website
  - I have been contacted by someone about disconnecting from the natural gas system – is it a scam?
  - What is System Pruning?
  - Why is Enbridge Gas doing this?
  - Do I have to disconnect if I am selected as part of the pilot?
  - What is the impact to my gas rates if I am not part of the pilot?
  - What rebates would I be eligible for if I am part of the system pruning pilot?
  - How do I join the pilot?

- Depending on customer uptake and information needs, this information may be supplemented as required
- Brochures and other information around heat pumps and other electrical conversions will be used
- Public customer information sessions to introduce the project and the general contractor
- Confirm that there is no need to update Save on Energy website

Implementation Approach – Pre-Screen

- There are many mains and customers (~100,000) that meet the Selection Criteria
- Propose two pilots:
  - A main with ~10 customers on it and;
  - ~ 10 individual services that are scheduled for replacement.
- Propose an interim step in which LDC's with many potential pilots are identified
  - Work with LDC to understand which potential pilots could be electrified without new transmission & distribution.
- Proposing a pre-screening step to give the best chance of testing the full pruning process (depending on the results of the survey):
  - In the case of a main, Enbridge will contact the customers to test interest in participation, willingness to provide access to utility bills as part of the pilot research, and willingness to provide feedback on the process.
    - If all customers on a street express at least an interest in participating, then that street becomes the pilot. Enbridge will confirm this with the customers and the general contractor will reach out to them
  - In the case of individual services, Enbridge will contact the customer to test interest.
    - Once ten have been identified in a region, Enbridge will contact them to confirm that they have been selected for the pilot and the general contractor will reach out to them in person
    - To make the delivery practical, Enbridge proposes that these 10 customers be geographically in the same Region and that the Region be different to the one where the pilot main is selected.
  - For customers that choose not to disconnect at the pre-screening stage, their reasons will be recorded for inclusion in the final report.

Implementation Approach – Field Work

Customer Engagement *(incorporating findings from focus group)*

- Pilot customers will be informed by physical letter and email
- For the pilot (main), Enbridge will host an information session to provide an overview of the project and answer questions. Includes introducing general contractor and the timelines for the pilot

General Contractor

- A general contractor will have accountability for responding to leads in a certain geography.
- The general contractor will meet with the customer to:
  - Educate them on the process, available rebates, costs and benefits related to converting to electricity.
  - Educate them on measures that can be taken to improve the building efficiency, and rebates that are available.
  - Educate them in a non-biased manner on the available appliances and equipment that are similar to their existing equipment, the functionality and cost.
  - Establish their interest in proceeding and timing for doing so
  - Coordinate with various trades to provide a seamless customer experience as appliances and equipment are exchanged, gas piping is removed, electrical upgrades are completed, and energy efficiency measures are implemented as required.
  - Coordinate with Enbridge so that meter and riser can be removed, service cut off at main and main abandonment completed.

Implementation Approach – Follow up

- For customers that have chosen not to disconnect during the field stage of the pilot, Enbridge Gas will contact them to understand the reason(s).
- For customers that choose to disconnect during the pilot, Enbridge will contact them:
  - Within one month of the work being completed to understand:
    - Their reasons for disconnecting
    - Their satisfaction with the process
    - Their satisfaction with the appliances and equipment that have been installed
  - After one year to understand:
    - Their satisfaction with the appliances and equipment that have been installed
- The information gathered through this research will be incorporated in the final report.
- Depending on the customers that do/do not disconnect, abandonment and replacement work will be completed by Enbridge.

Financial Analysis – Categories of Costs

- Replace Mains & Services
  - Base the cost on $/m for mains and $/service for services (2024)
  - Existing mains and services are abandoned
  - Relights required for customers
- Disconnect customers
  - General contractor costs to meet with customers and manage the experience whether they choose to disconnect or not:
    - If customer decides to not to disconnect there is expected to be some payment to contractor to cover their time and expertise in providing information and meeting with customers one or more times.
    - If the customer decides to disconnect the general contractor will oversee trades to provide a seamless experience to customers, and work with Enbridge to arrange for meter removal, service abandonment, final billing, etc
  - Abandonment of mains & services, removal of meter and riser
  - Customer offer
    - Amount for each customer will be based on existing equipment and appliances and general contractor assessment of what is needed to replace with similar electric.
    - Amount will also include an amount to cover the anticipated energy cost difference over a period of time and an incentive. These will be established through customer research.
- Non-pilot-specific costs
  - All costs leading up to the selection of a specific main or set of service for the pilot(s)
    - All work to develop the approach, engage the general contractor, identify candidates, pre-screen is considered project cost and is not attributed to a specific pilot and is deemed non-pilot-specific for this analysis.

Questions?

System Pruning Pilot

Presented April 17, 2025 for Input from the TWG Subgroup

ENBRIDGE

April 17, 2025

For Discussion

- Updates from March 26th TWG Meeting
  - Elements of the Approach
  - Pilot Objectives
  - Selection Criteria
- Contractor Strategy
- Evaluation Strategy
- Workplan to develop Approach

* Updates following the March 26th meeting of the Technical Working Group are in bold on each slide

Elements of the Approach

Enbridge has consulted with the TWG Subgroup to establish that these elements constitute the approach:

- Pilot Objectives
- Selection Criteria
- Customer Incentive
- Customer Engagement
- Customer Choice
- Stakeholder Engagement
- Program Delivery
- Implementation Plan
- Evaluation Strategy

Pilot Objectives

- Understand customer perspective on disconnecting from the NG distribution system.
  - What are customer perceptions and how do these drive their decision-making?
- Understand customer reaction to incentives and whether they can be incented to disconnect from the system in a way that is economic relative to the replacement of the mains and services.
  - Other than economics, what factors positively or negatively impact customer desire to convert?
  - The goal is to learn and document what the factors are – not to "force" a customer off the system.
  - ~~Customers will not be incented to move to a solution with higher overall emissions~~
  - While the pilot itself does not have to be economic, economics will be a consideration in the selection criteria where preliminary financial analysis will identify outliers to be avoided.
- Understand what data or other information is relevant to collect for the IESO and LDC in the pilot area
  - There was some discussion that sub-metering of the hot water and space heating could yield useful information
- Understand what works and does not work in program delivery
  - In terms of targeting customers, is it more effective to have a broad program at the individual service level or a targeted program at the main section level?
  - Procurement and contracting with participating contractor(s)
    - Fair and equitable for contractors that have the skills to guide customers through the process of converting to electric appliances & equipment
  - Initial and ongoing communication to customers on the pilot systems
    - How does Enbridge establish the legitimacy of the contractors and the process?
  - Contractor payment structure to drive good customer experience and low cost of delivery.
- Understand what policy and framework elements need to be reconsidered by the Ontario Energy Board if system pruning is to become a broader program.
  - This will be on a best-efforts basis. The pilot, being small, is not likely to turn up all policy and framework needs.

Pilot Selection - Sample Population Criteria

- Structured data search will include the following criteria for consideration as pilot candidates:
  - Targeted assets will be a part of the System Renewal Capital (i.e. cost of customer incentive is offset by the cost of the asset replacement)
  - Customers on dead end legs that are scheduled for replacement because of integrity & risk (E.g. vintage steel and Aldyl A)
  - Customers with services scheduled for replacement because of integrity & risk (E.g. farm taps, AMP Fittings, isolated steel)
- List will be reviewed with Operations, Integrity and Asset Management to identify omissions or inclusions.
- There are many mains and customers (~100,000) that meet the above criteria for consideration as a potential pilot candidate

Pilot Selection

- Propose two pilots:
  - Single main with ~10 customers on it and;
  - ~ 10 individual services that are scheduled for replacement.
- Enbridge will attempt to include at least one commercial customer in the pilot.
  - Agreement with TWG that this must be a customer where the decision-making for heating and cooling is limited to the building owner.
- *(In development)* The selection and pre-screening process to narrow down the list of potential pilot candidates to include consideration for:
  - Economics through preliminary financial analysis, including identifying outliers
  - Review with the LDC's and Municipalities to make sure there are no concerns in the area for electrical reliability, incorporating datasets from LDC/IESO if available.
  - Operational efficiency, pilot(s) can be effectively served by contractor
  - Pre-screening customer survey to establish initial response to electrification and increase likelihood that all pilot steps can be executed.
  - Diversity, i.e. customer type, home vintage, income, initial response

Contractor Strategy

- RFI issued April 14th to better understand how the services can be delivered.
- Issued to:
  - Summerhill
  - CLEAR Result
  - The Home Inspectors Group
  - EnviroCentre
  - Green Communities
  - Dunsky Energy + Climate Advisors

Evaluation Strategy

- The evaluation will compare Pilot Outcomes to the Pilot Objectives
- Financial analysis
  - Cost per conversion – compare actual versus estimated cost for each pilot customer (whether that customer chose to disconnect or remain on the system)
  - Change in energy bills
  - Consider variance by household type, equipment choice etc.
- Customer uptake
  - % uptake rate - compare actual uptake relative to the general survey (April) and the pre-screen
  - Consider influencing factors and/or characteristics of the participants/home
  - Customer rationale for participating/not-participating
- Program delivery effectiveness
  - Customer satisfaction/trust – post-installation survey for feedback
- Transferability of learnings
  - Understand the applicable transferability of the characteristics of the pilot location and customers to others in the gas distribution system

Workplan to Develop Approach

- Enbridge is seeking endorsement of its Approach for the System Pruning Pilot by Q2 2025. **Seeking confirmation of workplan deliverables**

Approach Element	Deliverables/Remaining Work
Pilot Objectives	Complete
Selection Criteria and Process	Sample population criteria – Complete Selection process – In Progress (inclusive of financial comparison of facility & non-facility alternatives)
Customer Offer	Pending input from Jurisdictional Scan and Customer Research
Customer Engagement	Complete – materials and questionnaires to be developed in pilot rollout
Customer Choice	In Progress – Flexibility Guidelines to be developed and bounded with Financial Analysis
Stakeholder Engagement	In Progress – IESO meeting scheduled. LDC meeting pending identification of pilot location.
Program Delivery	General approach – Complete. Additional details following input from RFI
Implementation Plan	General approach – Complete. Additional details following input from RFI and based on field experience.
Evaluation Strategy	In Progress

Questions & Discussion

- To ensure that all items in the Approach are finalized by June, Enbridge would like to advance some elements at the TWG.
  - Specifically, Enbridge would like to present the preliminary financial analysis at the TWG on May 7th, allowing time for the results to be incorporated into the approach elements as necessary.

System Pruning Pilot

Presented May 15, 2025 for Input from the TWG Subgroup

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May 15, 2025

For Discussion

- Customer Research findings and analysis
- Implication for Customer Offer and Selection Process
- Request for Information findings

Customer Demographics and Equipment Results

- Customers – live in older (and smaller) homes, same household size as customer population
  - 65% less than 2000 sq ft, 94% built before 1990 (customer reported – not MPAC)
  - 53% have 1 or 2 people living in them
  - 69% have no plans to sell in the next year
- Equipment – mostly similar to customer population
  - 86% have a natural gas furnace for primary heat; 5% have heat pump
    - 92% back their ASHP up with natural gas in some form
  - 80% have natural gas for hot water heating
  - These customers have about the same number of appliances
    - Lower penetration of stoves/ovens which is a high-cost item to replace
    - Higher penetration of pool heaters which is a high-cost item to replace
  - Likelihood to replace equipment in next two years does not appear to be different for this group

Natural Gas Penetration across Equipment	% from System Pruning Survey	% from 2024 Residential End Use Survey*
Home Heating – Furnaces (ASHP)	86% (5%)	79% (5%)
Water Heating	80%	78%
Fireplace	33%	37%
Cooktop/ Stove/Oven	26%	31%
BBQ	23%	21%
Clothes dryer	11%	13%
Pool heater	8%	4%
Generator	2%	n/a

Methodology and survey questions varied for each of these surveys and may explain some of the differences in results.

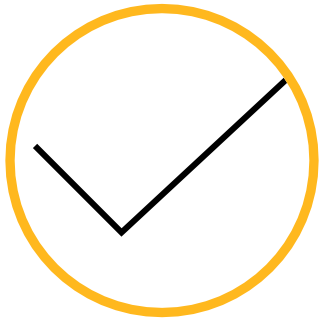
Respondent Segments: Mapping Disconnection Attitudes

- While most customers did not change their mind (67%) after seeing the additional offer elements, some became more interested, while others less so.



"Strong Adopters"

- 10% of respondents
- Already fully on board
- 'Definitely likely' to disconnect *before* and *after* reviewing the additional offer elements



"The Leaners"

- 23% of respondents
- They're leaning in, but may still need persuasion
- 'Somewhat likely' to disconnect *before* and *after* reviewing the additional offer elements



"The Persuadables" (Switched Up)

- 13% of respondents
- The offer worked – this group was influenced
- Switched *up* to 'Definitely/ Somewhat likely' to disconnect *after* reviewing the additional offer elements



"The Waverers" (Switched Down)

- 9% of respondents
- Initially open but lost interest/trust after reviewing offer elements
- Switched *down* to 'Somewhat//Not very/Not at all likely' to disconnect *after* reviewing the additional offer elements



"The Opposers"

- 31% of respondents
- Unmoved from the start – likely have strong objections
- 'Not very/Not at all likely' to disconnect *before* and *after* reviewing the additional offer elements



"The Fence Sitters"

- 14% of respondents
- Indicated 'don't know' *after* reviewing the additional offer elements

*Segments based on the initial sentiment and reaction to the offer components, specifically Q14 (initial likelihood of disconnection after reviewing the base offer) and Q28 (likelihood of disconnection after evaluating offer elements).
Note: This analysis was conducted by the Enbridge Gas Customer and Market Insights team to provide insights during the analysis and review period. It is not part of the final report and is intended to support targeted engagement by highlighting patterns across key audience groups. Please note that these groups are different from the groups presented in the final report.

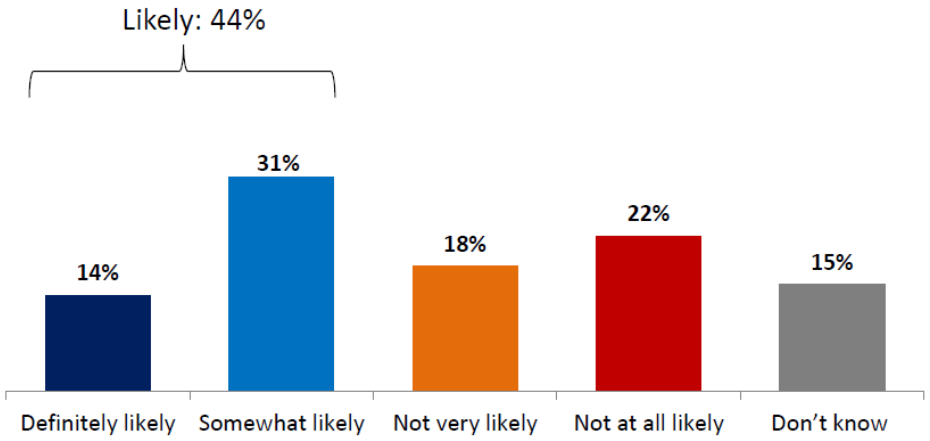
Customer Research

Elements of the Customer Offer

After Seeing the Base Offer:

- 39% say that allowing an **upgrade at their expense** makes the offer better (31% that it does not change the offer, 18% that it is worse).
  - This has limited cost to Enbridge Gas (administration only), and could enhance the offer for some customers, propose to include in the offer.
- 59% of customers think that **energy costs will go up**, 12% think they will stay the same, and 10% think they will go down.
  - Customers indicate that they **would like a bill guarantee** over an extended period. Administratively, it may be better to incorporate this in an upfront payment that compensates given a range of scenarios.
- 71% of customers are clear that they should be **informed about energy efficiency upgrades** and/or that the offer should **include top-ups with higher incentives** for these.
  - Given the support, the offer should include, at a minimum information about energy efficiency programs.

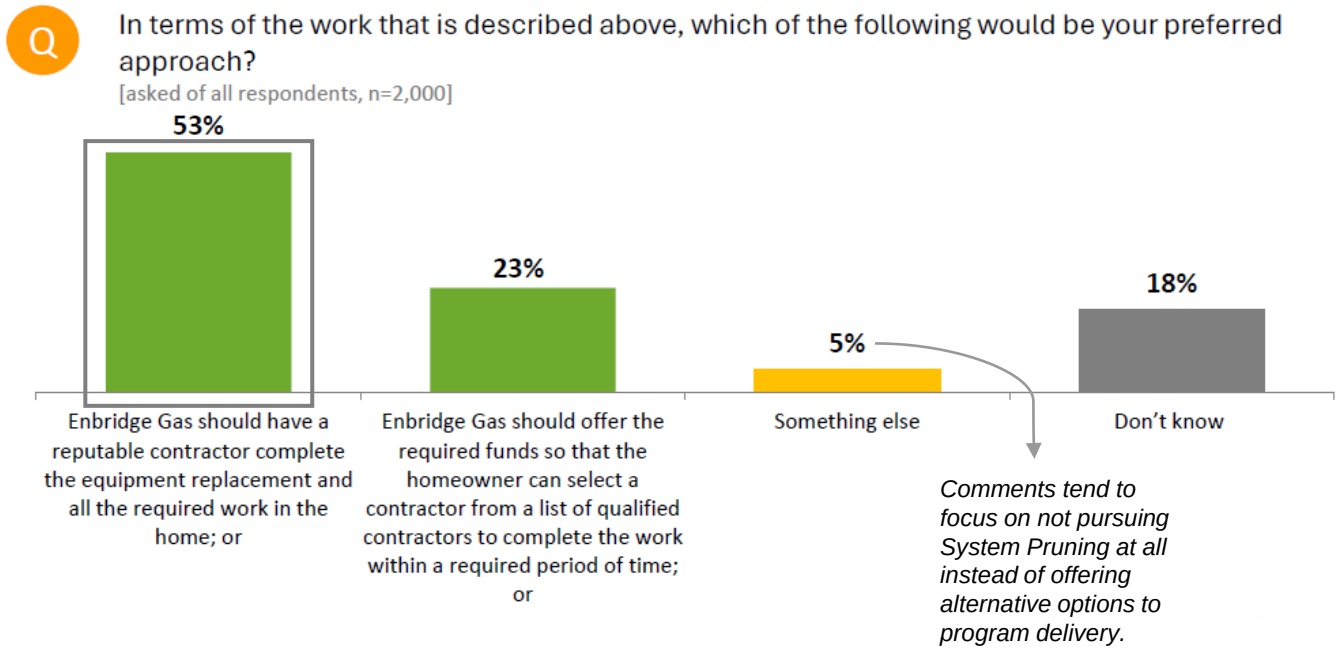
Q If this project were happening in your area, based on this offer, how likely would you be to agree to participate and disconnect?
[asked of all respondents, n=2,000]



Customer Research

Offer Delivery

- In terms of offer delivery, most customers felt that a reputable contractor should deliver the services.
- Requests for Information (RFI) for this work will offer additional insights on delivering the offer.



Customer Offer (recommendation)

- **Customer Research** shows that beyond the base offer of appliances and equipment, customers value different things.
- The preliminary **Financial Analysis** shows that conversion to electricity will not be economic in most cases.
- Recommended Offer:
  - Keep the **base offer** for all customers, this includes new equipment/appliances, the labour and materials to install them, labour and equipment to remove old equipment and their gas infrastructure, as well as make any electrical panel/service upgrades.
  - Customers may choose upgrades to the offer at their own expense.
  - Customer may receive an Energy Audit at no cost, and information about the upgrades and rebates that are available to improve the energy efficiency of the home.
  - Most customers value an extended warranty/guarantee on the work & equipment. If this can be arranged through the general contractor, then it would be good to include it as part of the offer.
  - Provide customers with an additional amount of $XXX which they can use to:
    - Offset increased energy costs (to be determined in consultation with the local LDC, for an amount equivalent to 5 years). Since it is not clear at this time whether the customer costs will go up or down, complete an analysis once the pilot area is selected and include an amount that covers 3-5 years of this extra.
      - Considering this as upfront payment informed by analysis - actual bill impacts will be influenced by usage changes beyond changes to the equipment
      - Given 59% perceive their energy costs will go up, beyond analysis/education may need to layer in payment as component of flexibility in implementation
    - Cover incidental costs if they need to take a day off work, make small repairs after equipment and appliance exchanges have been completed, or for other disruptions they may experience

Selection Criteria

- Use the results from Customer Research to narrow down the Selection Criteria and Process
- The sample is small, but customer research results shows variation in the initial response to the idea of pruning.

CITY	Likely*	Don't Know	# Respondents
North York	47%	17%	99
Etobicoke	40%	16%	80
Hamilton	48%	12%	60
Nepean	44%	16%	45
Burlington	45%	9%	45
Niagara Falls	45%	24%	37
Kanata	47%	14%	31
Pickering	52%	7%	28
Thornhill	46%	8%	25
Welland	48%	17%	24
Newmarket	52%	0	23

Table shows all cities where % Likely >40% and # Respondents >20.

*Likely (to participate if system pruning was a project in your area) is defined as a combination of customers who are 'definitely likely', 'somewhat likely', or increased their likelihood in response to the additional offer elements.

Selection Process & Implementation Next Steps

- Enbridge will bring data together to create a short list of pilot areas for consideration, filtered down using the following:
  - Financial analysis (or specific knowledge of commercial customers) shows facility replacement costs are high.
    - From the financial analysis, Enbridge has found that some of the customers with a high facility replacement costs are single customers with main.
  - Customers are generally more positive about electrification (based on Customer Research)
  - LDC can support electrification with existing infrastructure or planned upgrades (setting up discussions now)
- Proposed Pilots
  - One pilot with ~10 customers on a single street and;
  - One pilot with ~ 10 individual customers (residential or commercial)
- As part of implementation, Enbridge will engage customers through a pre-screening process to identify sentiment, appliances, and other demographics
  - A street level pilot with a mix of sentiments will provide greater learnings (no more than one “Opposer” and no more than two “Strong Adopter”). The “Opposer” must at least be willing to meet with the contractor for the street to be selected.
  - A street where at least some customers have more than space and water heating with natural gas will provide greater learnings.
  - Individual services will be in a different community to that of the street-level pilot and will seek to represent varying house size, sentiment, appliances, income.
  - Pilot selection will depend on the feedback through pre-screening and the pilot locations may need to vary to include two streets in the event individual customers are all strong "Opposers" in pre-screen, which will also inform learnings

Request for Information (RFI) Findings

- Enbridge issued an RFI to understand how contractors would deliver the more qualitative aspects of the service (unbiased, customer-focused) and how the contract should be structured to support this while maintaining project timelines and cost-effectiveness.
- Contractors provided ways in which they believe that they can deliver information that is fuel agnostic and unbiased with respect to specific equipment manufacturers.
- Contractors provided cost structures that include:
  - A Project Setup fee to develop processes, survey instruments, any materials that are to be left with customers, and training.
  - A per customer fee that covers the introductory discussion(s) with customers, inventory of appliances, discussion of alternatives and performance of building calculations
  - A fee to execute the work – most have proposed that this is variable because of the range of services that each customer may need.
- Some have contemplated a number of extras, including ongoing advice service for customers to help them keep energy costs low.
- Enbridge will incorporate these findings into the procurement process during pilot execution

2024

System Pruning Jurisdictional Scan

ENBRIDGE GAS – REQUEST FOR QUOTATION

OCTOBER 2024

ENBRIDGE
Life Takes Energy®

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Introduction

Enbridge Gas is seeking the services of an external consultant to perform a jurisdictional scan of system pruning activities. The objective of this report is to provide a greater understanding and obtain insights into how gas utilities among North American and European jurisdictions, where informative to the Ontario context, are approaching pruning of their gas distribution pipelines. This report is intended to provide Enbridge Gas, the IRP Technical Working Group (IRP TWG) and the Ontario Energy Board (OEB) with a foundational understanding of system pruning approaches, best practices and lessons learned to assist in the development of a potential system pruning framework and pilot in Ontario.

Background

In the Phase 1 Decision to Enbridge Gas' Rebasing Application (EB-2022-0200), the OEB introduced the concept of system pruning as a way to reduce system. System pruning involves the strategic and proactive decommissioning of a portion of the natural gas system through education and/or incentivization of existing customers to willingly disconnect from the gas system, thus rendering that specific portion of the pipeline no longer required to serve their energy needs. System pruning will also avoid capital costs associated with replacing a section of the distribution pipeline system once customers have fully disconnected from the system. To proceed with the pruning of a targeted portion of the system, all customers served by that pipeline system must have fully converted off natural gas and be willing to disconnect from the pipeline system. The OEB gave the example of "converting a subdivision from gas to electricity for space and water heating" and stated that system pruning could be supported by an IRP solution, which would include supporting existing customers in replacing their gas equipment with electric equipment to avoid the need the replace the facility.[1]

In its Phase 2 Evidence, Enbridge Gas outlined its approach to system pruning to include engagement with the IRP TWG to consult on system pruning processes and what role the Company could play in a system pruning pilot. To inform this work, Enbridge Gas noted it would complete a scan to identify how utilities in other jurisdictions are approaching gas system pruning to identify best practices, where available.

IRP Technical Working Group Engagement

Enbridge Gas intends to work collaboratively with the selected consultant and members of the IRP TWG (collectively or a subcommittee) throughout the jurisdictional scan process. The Consultant and all participating members are expected to follow the norms set forth by the Terms of Reference of the TWG.[2] As part of their quote, the Consultant should include regular meetings to receive input on and review progress of the study. The quote should indicate the number and timing of TWG meetings with justification.[3]

[1] EB-2022-0200, Decision and Order, December 21, 2023, p.52.
[2] Terms of Reference
[3] The actual number and timing of meetings will be determined jointly by Enbridge and OEB staff with input from the consultant.

For clarity, in terms of approach:

- The Study is being conducted for, and on behalf of, Enbridge Gas, OEB Staff, other members of the IRP Working Group and, ultimately, all Enbridge ratepayers.
- Where non-contractual or administrative decisions are required for the Consultant through the course of the jurisdictional scan, they will be informed by the information/recommendations of the Consultant and in consultation with the members of the IRP TWG (collectively or a subcommittee). If the members cannot reach consensus, the Consultant shall review feedback and make the decision, taking into account all comments and discussions, as well as the approved scope and budget. The Consultant will document any disputed issues within the final deliverables along with the Consultant's position, Enbridge Gas's position and the other members' positions.
- With the exception of communications related solely to the contractual or other administrative issues between the Consultant and Enbridge Gas, all written communications between the Consultant and TWG members shall be copied to the subcommittee (if used) or all members (if no subcommittee). Similarly, a summary of any oral communications will also be shared by the Consultant.
- If a subcommittee is used, members will be selected by OEB Staff in conjunction with the TWG. The Consultant will not participate in the selection process.
- Any member of the IRP TWG who works for the Consultant's firm will be representing their firm during jurisdictional scan discussions. For other topics, they will continue to represent themselves as individuals, not a representative of a specific organization.
- If a subcommittee is used, the Consultant will coordinate jurisdictional scan meetings that involve TWG subcommittee members. The meetings will also be attended by OEB Staff. The Consultant will chair the meetings, circulate agenda items, and record key meeting outcomes. The outcomes will not be posted to the OEB website but will be accessible upon request to any TWG members, including those not participating on the subcommittee. The consultant will keep OEB Staff informed of the expected participation time of IRP TWG members and work with OEB Staff to resolve any concerns regarding the expected participation time. Updates on the progress of jurisdictional scan work will be provided to the full IRP TWG at the regular IRP TWG meetings, with discussion documented in meeting minutes and posted to the OEB website.
- The selected consultant will be responsible for the final materials delivered as a result of the jurisdictional scan. OEB Staff will post the deliverables on the IRP TWG website.

Study Objectives

1. Landscape assessment to identify which jurisdictions are undertaking gas system pruning projects.
2. Targeted research of utilities to conduct a deeper dive on gas decommissioning strategies and practices, supplemented with 1:1 interviews with utility staff, government staff, and/or regulatory staff to discuss process and experience.

3. Final report on each utilities' processes and identification of emerging best practices/practices to avoid across utilities, lessons learned, and information gaps.

Scope of the Study

The scope of the study includes the following areas:

Task 1 – Landscape Assessment

Jurisdictional landscape assessment to identify which jurisdictions or utilities are pursuing gas system pruning and, depending on the number of jurisdictions pursuing this, select a subset to conduct a deeper dive for the purposes of this report. The number of jurisdictions selected will be informed by the landscape assessment, the stage that the identified jurisdictions are at with respect to their considerations and action on system pruning, and the degree of potential insight and transferability of learnings to Ontario.

Deliverables include providing a list of the jurisdictions or utilities pursuing system pruning or gas decommissioning, and highlighting the stage they are at and any system pruning initiatives undertaken.

Task 2 – Identification of Targeted Utilities

Based on the results of the landscape assessment, this task will include developing the Consultant's recommendation for the subset of jurisdictions and utilities for the targeted research stage to conduct a deeper dive into their system pruning processes, with associated justification for the jurisdictions included (and excluded where relevant) based on the results of the landscape assessment. The Consultant will work with Enbridge Gas and the IRP TWG to confirm the structure of the report, and key questions for 1:1 interview with utility employees and other stakeholders as required.

Deliverables include providing a list of targeted utilities with recommendation and justification for the targeted research stage, draft structure of the report, and key interview questions.

Task 3 – Targeted Research and Interviews

Within selected jurisdictions, targeted research and interviews will be conducted to take a deeper dive of their gas decommissioning strategies and practices through secondary research, supplemented with direct communication with utility staff to provide further learnings (to be conducted with both an Enbridge Gas staff and TWG representative in attendance. To further understand the jurisdictional context, interviews with government or regulatory staff (or other active stakeholders) may be included. This will cover the following areas from the intended scope of the report, including:

- Jurisdictional context and background, including regulatory decisions, gas planning frameworks, and government legislation related to gas decommissioning planning and projects.

- Utility objectives and/or drivers underpinning the pursuit of system pruning activities (e.g. rate of expenditure on pipeline integrity potentially influenced by materials that have been in use in the jurisdiction, utility/customer/jurisdictional considerations like size/type of utility, customer make-up, regional construction practices, climate, and utility/customer decision-making drivers).
- An overview of each utilities' approach to system pruning projects and/or programs including:
    - The screening criteria (if any) to identify potential pipeline candidates, and associated process considerations.
    - The criteria and methodology to prioritize and select feasible potential pipeline candidates (including whether any verification of the information driving the investment need avoided through pruning that segment of the system).
- Utility structure (i.e., gas-only, joint gas/electric), and the extent to which natural gas utilities pursuing system pruning are coordinating those efforts with affected electric utilities, as well as the nature of any such coordination.
- The methodology to evaluate the cost effectiveness of pruning to compare alternatives.
- Customer engagement practices throughout the process, from assessing initial customer sentiment for potential candidate systems through to strategies for achieving participation and disconnection from the gas system.
- Policies and strategies for "hold outs" in situations where most customers are prepared to fully electrify but a very small number or portion are not.
- Funding sources for system pruning projects (i.e., electric ratepayer, gas ratepayer, government).
- Program design and offer to customers, inclusive of the scope of non-gas building and water heating alternatives (e.g. electric heat pumps, thermal networks, requirements around not supporting transition to higher-emissions fuels) and partnership considerations and how barriers are addressed.
- Deployment plan and associated program delivery approaches
- Summary of projects completed to date or anticipated to be completed (number of completed projects and, for each such project, the pipe characteristics, number and type of customers attached, time horizon for project completion, costs, any gas system cost savings, challenges, successes experienced, etc.).
- Utility incentives to implement system pruning/how disincentives have been addressed.
- How the costs of proposed alternatives are treated for rate making purposes, how the costs are recovered, and any changes to utility rate design.

Deliverables include a summary of research, interview questions and responses in Word format.

Task 4 – Identification of Commonalities and Divergence Across Jurisdictions

The section will identify key areas of commonality and divergence across the identified jurisdictions, and to the extent possible the drivers behind them. This will cover the following areas from the intended scope of the report, including:

- The screening criteria to identify potential pipeline candidates, and associated process considerations.
- The criteria and methodology to prioritize and select feasible potential pipeline candidates.
- Coordination and integration processes between natural gas and electric utilities.
- The methodology to evaluate the cost effectiveness to compare alternatives.
- Customer engagement practices along the process, from assessing initial customer sentiment for potential candidate systems through to strategies for achieving participation and disconnection from the gas system.
- Policies and strategies for “hold outs” in situations where most customers are prepared to fully electrify but a very small number or portion are not.
- Funding sources for system pruning projects (i.e., electric ratepayer, gas ratepayer, government).
- Program design and offer to customers, inclusive of scope of non-gas building heating alternatives (e.g. electric heat pumps, thermal networks, requirements around not supporting transition to higher-emissions fuels)
- Deployment plan and associated program delivery approaches.
- Key elements of projects completed to date or anticipated to be completed (pipe characteristics, number and type of customers attached, time horizon, costs, challenges and successes experienced, etc.).
- Utility incentives to implement system pruning.
- How the costs of proposed alternatives are treated for rate making purposes, how the costs are recovered, and any changes to utility rate design.

Deliverables includes summary of findings.

Task 5 – Emerging Best Practices

This section will identify a set of emerging best practices among the utilities studied. Best practice is defined, for the purpose of this report, as a practice either documented in a utility report or stated by an interviewee as contributing to program success for at least one of the utilities reviewed, and ideally across multiple utilities. For example, may include but not limited to strategies on the following components:

- Criteria and methodology to prioritize candidates.
- Coordination among gas and electric utilities (i.e., planning tools).
- Customer engagement practices.
- Policies and strategies for “hold outs”.
- Program design and deployment practices.

Deliverables includes summary of findings.

Task 6 – Identification of Lessons Learned

This section will provide an overview of lessons learned and barriers to success either identified in a utility report or stated by an interviewee. For example, may include but not limited to discussion such as:

- Process learnings internal to the utility.
- Key findings from projects initiated and completed.
- Barriers experienced such as findings on customer preferences and key factors impacting opt-in participation for gas decommissioning projects.

Deliverables includes summary of findings.

Task 7 – Information Gaps

This section will include what information was missing, unclear or unable to be obtained through the execution of this work. This may include an overview of the encountered limitations in information available in the targeted jurisdictions, any context on challenges encountered, and any considerations in light of these limitations.

Deliverables includes summary of findings.

Task 8 – Final Report

Deliverable includes a final report consolidating all research findings, and discussion of identified commonalities/divergence, lessons learned, and best practices, to be provided in Word format.

Deliverables

Consultant should provide the following deliverables:

1. Landscape Assessment showing all jurisdictions implementing gas decommissioning.
2. List of recommended jurisdictions and utilities for the targeted research stage.
3. Research results and interview findings for targeted jurisdictions/utilities, including interview questions, notes and responses.
4. Summary of system pruning commonalities/divergence, best practices, lessons learned, and information gaps across jurisdictions.
5. Final Report – consolidation of all research and findings.

Proposed Schedule

The following schedules and deadlines apply:

Request for Quotation Issued	November 1, 2024
Quotation Due Date	November 6, 2024
Notice of Contract Award	November 13, 2024

Quotation Format

1. Approach & Methodology
    - Provide a description of any recommendations of the Consultant towards the objectives outlined that differ from the tasks and approach outlined in the study scope.
2. Study Timeline & Cost Estimate
    - Provide the proposed study timeline in table format.
    - Provide a budget table for all major phases and milestones of the study, broken out by task. Please include the hourly rate and estimated number of hours for each project team member in the budget table. Additionally, please include the hourly rate for potential Regulatory support (as required), inclusive but not limited to witness and interrogatory support.
3. Study Team
    - Identify the proposed project team by personnel and task.

Please submit quotation to:

David Moffat – david.moffat@enbridge.com

INTRODUCTION / LANDING PAGE

Welcome!

The goal of this form is to gauge your interest in participating in our **All Electric Pilot Project.**

Participating in this step and this pilot project is completely voluntary; this form is meant to help Enbridge Gas and its selected contractor identify potential participants.

Completing the form does not guarantee that you will be part of the pilot project, however it is an important part of the process, and we appreciate your participation.

Note: this form is the same for both the email invitation and the link on the website. You only need to fill out the form once.

We are looking to hear from the homeowner, or the person who is responsible for making energy decisions, for the property. If that isn't you, please forward the invitation to review the material and the form to the right person.

Please indicate your address:

The purpose of sharing your address is to confirm that your property is located within the potential project area.

STREET NUMBER:

STREET NAME:

CITY:

POSTAL CODE:

Do you own or rent this property?

- Own
- Rent

main survey

Based on the information provided to date, how likely are you to agree to participate in the pilot and in doing so disconnect from natural gas?

Please note answering this question does not mean that you will be participating in the pilot project. Enbridge Gas fully expects that you will need more information; however, this initial question will help us understand who may consider participating.

- Definitely likely
- Somewhat likely
- Not very likely
- Not at all likely
- Don't know

What are the main reasons you are "${q://QID6/ChoiceGroup/SelectedChoices}" to agree to participate?

What are the main reasons you are unsure about whether you would agree to participate?

Enbridge Gas will be working with an independent third-party contractor to discuss the options available, answer customer questions, and provide more information.

To proceed, would you like to discuss with a contractor about what this pilot project might look like for your home? If yes, Enbridge Gas will share your contact information with the contractor so they can reach out to you. Would you like to proceed with this step?

- ○ Yes
- ○ No

By sharing your information, you agree to receiving marketing and service-related communications from Enbridge Gas for the purpose of this pilot.

Name:

Phone Number:

Email Address:

To help us better understand the natural gas equipment in your home, we would like to understand how you are currently using natural gas.

How do you primarily generate heat in your home?
Please review the options carefully.

- ○ Air source, or electric, heat pump (Note: this means you have a heat pump that uses electricity to generate heat, we'll ask you about any backup equipment you may have in the next question)
- ○ Ground source heat pump, also known as electric geothermal
- ○ Natural gas furnace (Note: don't select this option if you have a heat pump)
- ○ Natural gas boiler or hot water radiator
- ○ Natural gas fireplace for primary home heating
- ○ Oil furnace

- ○ Electric furnace
- ○ Electric baseboards
- ○ Propane heating
- ○ [ ] Other:
- ○ Don't know

Do you have any other home heating equipment as a backup, and if so, what kind of equipment do you have? *Select all that apply.*

- ☐ Natural gas furnace
- ☐ Natural gas boiler or hot water radiator
- ☐ Natural gas fireplace
- ☐ Electric furnace
- ☐ Electric baseboard
- ☐ Electric boiler or hot water radiator
- ☐ Electric fireplace
- ☐ Wood stove
- ☐ [ ] Something else not listed here
- ☐ No, I don’t have any backup home heating

Do you use natural gas for any of the following in your home? *Please select all that apply.*

- ☐ Natural gas fireplace for supplementary home heating or ambiance
- ☐ Hot water / Water heating
- ☐ Cooktop / Stove / Oven
- ☐ BBQ
- ☐ Clothes dryer
- ☐ Pool heater
- ☐ Generator
- ☐ [ ] Anything else not listed above (please specify):
- ☐ None of the above / no other
- ☐ Don’t know

Which of the following best describes how heating is delivered in your home? *Select all that apply.*

- [ ] Forced air / fully ducted system
- [ ] Hot water radiators (rads)
- [ ] In floor radiant heating
- [ ] Ductless (mini split)
- [ ] _____ Other (please specify)
- [ ] Don’t know

Do you currently have a system for cooling your home (e.g., air conditioner)

- ○ Yes
- ○ No
- ○ Don't know

Which of the following types of air conditioning do you use in your home? Select all that apply.

- [ ] Central air conditioner
- [ ] Window air conditioner
- [ ] Wall mounted or ductless unit (mini-split)
- [ ] Portable air conditioner
- [ ] Geothermal / ground source heat pump
- [ ] _____ Other (please specify:)
- [ ] Don't know

How old is your equipment below? If needed, please share your best guess.

	Less than 1 year old	1 to 2 years old	3 to 5 years old	6 to 10 years old	11 to 15 years old	16 to 20 years old	More than 20 years old	Don't know
Natural gas boiler or hot water radiator	○	○	○	○	○	○	○	○
Natural gas fireplace for primary home heating	○	○	○	○	○	○	○	○
Natural gas furnace	○	○	○	○	○	○	○	○
Natural gas boiler or hot water radiator	○	○	○	○	○	○	○	○
Natural gas fireplace	○	○	○	○	○	○	○	○
Natural gas furnace (Note: don't select this option if you have a heat pump)	○	○	○	○	○	○	○	○
Natural gas fireplace for supplementary home heating or ambiance	○	○	○	○	○	○	○	○
Hot water / Water heating	○	○	○	○	○	○	○	○
Cooktop / Stove / Oven	○	○	○	○	○	○	○	○
BBQ	○	○	○	○	○	○	○	○
Clothes dryer	○	○	○	○	○	○	○	○
Pool heater	○	○	○	○	○	○	○	○
Generator	○	○	○	○	○	○	○	○
AC	○	○	○	○	○	○	○	○

DEMOGRAPHICS

Now we would like to ask you some questions about your home and your household.

○ Including yourself, how many people in total live in your household?

[ ]

○ Prefer not to answer

Just a few more questions...

- ○ [ ] What is your age?
- ○ Prefer not to answer

Into which of the following age categories do you fall?

- ○ 18 to 24
- ○ 25 to 44
- ○ 45 to 64
- ○ 65 to 74
- ○ 75 or older
- ○ Prefer not to answer

Which of the following best describes your total annual household income (after taxes)?

- ○ $39,999 or less
- ○ $40,000 to $59,999
- ○ $60,000 to $79,999
- ○ $80,000 to $99,999
- ○ $100,000 to $124,999
- ○ $125,000 to $149,999
- ○ $150,000 and over
- ○ Prefer not to answer

Do you have any other comments you would like to share?

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OUTBOUND CALL SCRIPT – Enbridge's System Pruning Pilot (SPP) – "Pilot Program"

Enbridge will provide list of potential homes

- *Add the customer to Praxedo.*
- *Call the customer to review the Work Order (WO).*

Greeting

"Hello this is [Your Name] calling from The Home Inspectors Group. You previously responded to an Enbridge Gas customer interest form in Fall 2025, indicating you were interested in participating in a pilot to convert your home's natural gas equipment to non-natural gas options and fully disconnect from natural gas. You noted you'd like to learn what this pilot could look like for your home *(customer may know this as "All Electric Pilot")*. We're the delivery agent for this pilot on behalf of Enbridge Gas, and you've been identified as eligible to participate. Is now a good time to chat?"

- ***If there is concern that this is a Scam***
  - *Direct the homeowner to Enbridge's call centre, who will confirm legitimacy.*

Confirm details:

- Customer's address.
- Ask if they are familiar with the program.
  - **If not** - Proceed with program explanation:
  - This is a pilot program offered by Enbridge Gas to select homeowners. Enbridge covers the cost to convert the home from natural gas to electric or other non-natural gas options, including heating systems, appliances, required electrical upgrades, and removal of gas equipment. Once the project is complete, natural gas would be disconnected from the home (and property will be restored in the work areas to its original condition)
- **Additional Program highlights:**
  - A home visit will be scheduled with an Energy Advisor to review the program in more detail and take inventory of the natural gas appliances and equipment in the home.
  - A contractor will visit the home to determine the details of the features and functionality of your existing equipment and appliances so that the offer can ensure the new models available to you are comparable to what you currently have in your home. If you'd like to upgrade any of the equipment beyond what would be comparable, you will have the option to fund the difference to upgrade it. You are under no obligation to proceed with the conversion during the home visit.
  - Enbridge will prepare a customized offer for you and send it to you by email. It will detail the appliances and equipment that will be installed in your home, as well as any other work required to upgrade your electrical system and disconnect you from the natural gas system. You will be required to sign this Participant Agreement before any work will proceed.
  - We would handle all the logistics, installation and removal of equipment for your home.

- Participation requires a commitment to provide two years of electricity usage data at the start of the program, and another two years of usage data after the conversion.
  - *The homeowner can login to their LDC (local distribution company) and download this information. Our representatives can assist you in understanding that process.*
- The program includes an EnerGuide audit at no cost, which would be scheduled after the offer is accepted by the homeowner. This audit would help identify additional energy efficiency upgrade opportunities in the home, such as insulation improvements, and allow you to decide whether you'd like to take advantage of Enbridge Gas's existing energy efficiency offers/rebates before proceeding with the pilot to convert your natural gas equipment and appliances. ***Note:*** *THIG will only proceed with an energy audit and the installs if the homeowner commits to convert off of natural gas.*
- The pilot is aiming to complete all conversions before the 2026 heating season *(work can begin any time but the timing for the exchange of the heating equipment will be weather dependent)*
- Participation requires completing two surveys:
  - First Survey - after the work is completed
    - The first survey will focus on your experience with the process.
  - Second Survey - approximately one year after conversation
    - The second survey is meant to gather feedback on your new equipment, including your thoughts on your appliances and whether your energy costs are higher or lower than expected.

- ***Why is it free?*** *(only if a homeowner asks)*

  This is a pilot program designed to help Enbridge Gas and the Ontario Energy Board evaluate the effectiveness of converting homes off of natural gas to an alternative energy source. The pilot will consider learnings including customer interest, experiences, and cost of these alternatives to the costs of replacing natural gas infrastructure requiring renewal. Like the costs for pipeline upgrades, the costs of this pilot are covered more broadly through natural gas rates, not just by individual customers participating in the program—so you can take part at no direct cost.

Are you interested in moving forward to the next steps?

- **Yes** – continue
- **Not sure** – ask:
  1. Do you have any questions or concerns, or are there any clarifications we can provide?
  2. Would you like some more time to think about this, we can give you a call back in a few days? *Schedule follow-up with customer (date and time for call).*
- **No** – ask:
  1. What are the main reasons that you are no longer interested in participating?
  2. Learning is an important part of this pilot - are there things missing from the offer that would have caused you to think differently about participating?

3. Were you satisfied with the process that was followed in engaging you on the offer and discussing your questions and comments?
4. Is there anything that could be considered to improve the process or how you were engaged in discussing the offer?
5. Is there any other feedback you would like to share with Enbridge Gas or the Home Inspectors Group to improve the pilot program? This could be about the program itself, the process or steps, the communication and information provided?

If customer wants their own contractor:

- This is reviewed on a case-by-case basis with Enbridge. Ask:
  1. Why do you wish to use your own contractor?
  2. What contractor do you wish to use (and for which items)?
- Advise homeowner we will call back once the determination is made.
- Advise the homeowner that next steps will be outlined if approved, do not proceed with any installations before approval.

Enbridge Gas account

- Based on our records, you currently have an active Enbridge gas account, is this correct?
- **Yes** – continue
  - Is there anything that you are planning that would impact your account, such as a planned move, at this time?
    - *Home not excluded / call not ended if they are planning a change to the account such as a move in future, will be considered on case-by-case.*
- **No** – not eligible, ask: why do you no longer have a gas account?

Primary and Supplemental heating

- Based on the pre-screening, your primary space heating source is: [Indicate the heat source listed on the pre-screening data], and your supplemental heating source is [Indicate the heat source listed on the pre-screening data],is this correct?
- ***Any*** *natural gas heating system is eligible for non-natural gas replacement (furnace, boiler, fireplace), as well as the consideration of requirements in the case of a heat pump where there is currently natural gas supplemental heating. If the homeowner indicates the home does not have natural gas heating they would be eligible for the replacement of their other natural gas equipment.*

Other Program Participation

- Ask: "Are you participating in any other programs (HRS, GH, HER+, HER24, 40K Loan)?"
  - **Yes:**
    - At what stage of the program are you?
    - Do you have a timeline for completion?
    - Advise customer that they should finish their current program first. Once complete, call THIG and begin enrollment in this pilot afterwards.

- **If pushback:** Advise that you'll review with the program coordinator. *(Enbridge may allow another program, e.g. HRS if the homeowner wants to do insulation, which could benefit the sizing the of the new equipment, this would be reviewed case by case).*
- ***Important:*** *home must still have gas account after participation in another program in order to proceed with System Pruning afterwards. Heating system should be changed through System Pruning (not through HRS as an example).*
- **No**: continue.

Ownership

- Ask:
  - Based on the pre-screening, you are the owner of this property, is that correct?
  - Do you rent the property?
    - Both are eligible.
    - **Renting, advise:** your landlord needs to proceed with the program.

Home Type

- Ask: "Is the home detached, semi-detached, or a row house?"
- If row house, ask: "Are the units stacked with separate entrances?"
- If yes → Classified as MURB (Multi-Unit Residential Building) – eligible for System Pruning, not eligible for energy audit or rebate program, note: **do not** offer or discuss the energy audit for MURB.

Year Built

- Based on our records, you home is: [Include age of home] years, is that correct?

House Size

- Based on our records, you home size is: [include house size], is that correct?
- ***Reminder:*** *If OVER 6400 Square Feet still proceed with intake (an EnerGuide audit will not be done, but a non-EnerGuide energy audit can be conducted in general mode).*

Additions / Extensions

- Ask: "Do you plan on adding an addition or extension?"
  - If yes, move to next question
- Ask: "When are you planning to START the addition/extension?"
  - Additions/extensions are NOT COVERED by System Pruning. System Pruning (the audits and installation) must be completed BEFORE any additions/extensions.
    - Proceed with intake and schedule visit
  - If additions/extensions are expected during the duration of System Pruning:
    - Ask what the addition and extension entail
    - Advise homeowner we need approval from Enbridge to proceed
    - Customer will need to cover costs for additional work, it is NOT COVERED by System Pruning

        - Continue with intake, but **do not** schedule visit, advise customer we will call back.

Natural gas appliances and equipment

- Based on the pre-screening your current gas appliances and equipment are *(check those that apply)*:
    - *Water Heater (DHW)*
    - *Fireplace*
    - *Stove*
    - *BBQ*
    - *Clothes Dryer*
    - *Pool Heater*
    - *Driveway Heater*

Renovations / Construction

- Ask "if any renovations are currently underway"
    - Open walls or ceilings?
    - Windows/doors removed?
    - Heating equipment removed?
    - Is the home habitable?
- **If yes**,
    - Ask for more information on the condition of the renovations
    - Ask for a timeline
    - *The Pilot may continue depending on the condition. For ERS audit purposes, determine if an EnerGuide audit can be offered and conditions can be met for the blower door test.*

Booking Initial Visit

An Energy Advisor will come to your home to review the equipment and appliances currently using natural gas, walk you through what a conversion would involve, and answer any questions about the program. If you choose to proceed, Enbridge will send you an agreement to start enrollment.

Proceed with looking at EAs schedule and agreeing on date and time

- **Mandatory Reminders for Customer**
    - Are all rooms accessible?
        - **If yes**, proceed to next question
        - **If no,** ask: what rooms are not accessible? *(we need to access all gas and electrical areas to determine the scope of work)*
    - Are there any tenants in the home?
        - If yes → ensure EA can access all units.
- **Required documents:**
    - Enbridge Gas Bill

    - Remind homeowner that after the visit there will be a customer commitment to provide two years of electricity usage data at the start of the program, and another two years of usage data after the conversion.
        - *The homeowner can login to their LDC (local distribution company) and download this information.*
- Parking: Street or driveway?
- Confirm appointment date, arrival time (±1 hour), and EA name.
- Update Call Status to Booked
- Send email to customer

Reminder: *an energy audit is offered to the homeowner once the homeowner accepts the Enbridge offer and enrollment is confirmed. Homeowner will get a call back to book the energy audit.*

Booking the ERS Audit

Proceed with looking at EAs schedule and agreeing on date and time

- **Mandatory Reminders for Customer**
    - Are all rooms accessible from on main entrance?
        - If yes, proceed to next question
        - If no, must make sure otherwise can not do audit
    - Are there any tenants in the home?
        - If yes → ensure EA can access all units.
    - Wood-burning fireplace?
        - If yes, ashes must be removed before audit

- **Required documents:**
    - Property Tax Bill (dated within 1 year).
        - Whoever's name is on the Tax Bill, will they be present for the audit? If no, we will need to send docs to be signed and sent back before the audit.
    - NRCan form
- Is there Access to the attic from: inside, outside, no access – case by case (may be non ERS audit)
- The EA will be using his ladder to access the attic, is there anything blocking the attic hatch?
        - If yes, must be cleared
        - If no, proceed to next question
- Parking: Street or driveway?
- Confirm appointment date, arrival time (±1 hour), and EA name.
- Update Call Status to Booked
- Send email to customer

INNOVATIVE RESEARCH GROUP

Online Focus Groups

Discussion Guide

Enbridge Gas Inc.

February 2025

Discussion Road Map

Sections and Topics	Approx. Time
Introduction	10 minutes
Introduction to Asset Management and IRP	5 minutes
System Pruning	15 minutes
Incentive Offer	30 minutes
Incentive Mechanism	30 minutes
Other Concerns	10 minutes
Final Thoughts?	10 minutes
Estimated Total Time / Session	**(1 hrs 50 minutes)**

Section 1: Introduction

(Time: 10 minutes)

Thank participants for attending the in-person group.

Advantages

- Can explore topics and get a sense of what sort of questions to ask in surveys.
- We are looking for a range of views and considerations tonight, we are not trying to settle anything here.
- Need for everybody to participate.
- Discussion – one at a time.
- Your privacy matters. All individual responses will be held in confidence and will be combined with the responses of others.

Disclosure:

We are an independent company. Our role is like auditors, except instead of providing an independent take on Enbridge Gas' finances, we provide an independent review of customer opinions.

- My job – keep discussion focused – get through topic areas.
- This session is being video and audio taped.
- Confidentiality and neutrality of moderator.
- Colleagues joining us on this call.
- Reasons for taping.

Ground Rules:

Let everyone have air time – avoid side discussion among participants, avoid more than one person talking at a time. Feel free to jump in.

Introduce self and ask participants to introduce themselves. Ask participants to briefly explain:

- How do you use natural gas in your home?

- Has anything changed recently in how you use natural gas in recent years?

Introduce self and ask participants to introduce themselves/business.

- First name
- What do you do when not in focus groups?

Section 2: Introduction to Asset Management and IRP

(Time: 5 minutes)

Tonight, we will be talking about your natural gas utility Enbridge Gas.

- Have you ever heard anything about the natural gas distribution, or pipeline, network in Ontario and how Enbridge Gas manages that? *(Look for some common words or themes that relate to asset management)*.
- Enbridge Gas has many kilometers of pipelines in the ground in Ontario. It manages the maintenance and replacement of this network of pipelines through its asset management plan and considers requirements by the Ontario Energy Board.

SHOW SLIDE

When considering the work it needs to do, specifically its **pipeline projects**, Enbridge Gas is required by the Ontario Energy Board (OEB) to evaluate whether **non-pipeline alternatives** are available that would delay, reduce, or eliminate the need for the project.

Examples of potential **non-pipeline alternatives** include:

- Helping customers reduce the amount of natural gas they use through conservation programs or other options. Examples could include:
  - Incentives for installing new windows and doors; and/or
  - Adding insulation; and/or
  - Upgrading equipment, such as a furnace or water heater.
- Shifting customer's peak hour gas demand through demand response programs (this type of program encourages customers to use less gas during times of high demand)
- Delivering compressed natural gas by truck to locations
- Securing more natural gas through third parties in a specific area

In industry terms, this enhanced planning strategy and process is called IRP or **Integrated Resource Planning**.

SHARE QUESTION BELOW

Enbridge Gas has prepared the following description to explain one of the requirements at a high-level, does this make sense to you? Is there anything missing?

Section 3: System Pruning

(Time: 15 minutes)

Now let's go a little deeper to another option that could be considered.

- Enbridge Gas has prepared the following description to explain this option at a high-level,

SHARE SLIDE

For each pipeline project, alternatives discussed earlier are evaluated from a **technical and economic perspective**.

There is also another option that could be considered for replacement type projects.

This option would apply for a single street, or a smaller area, and is something called System Pruning. This means that instead of repairing or replacing a pipeline, Enbridge Gas would give affected customers the option to disconnect from the pipeline. If everyone disconnects, then instead of repairing or replacing it, this pipeline could be removed.

The affected customers would need to rely on other energy sources, such as electricity to fuel their equipment and appliances. The funds no longer needed for the pipeline can be used to support the disconnection and help customers through the process.

SHARE QUESTION BELOW

Does this approach seem reasonable to you?

PROBES

- Does this make sense to you? What do you think about it? What questions come to your mind when you read this?
- What if the removal of the natural gas pipeline was considered for your area? How would you react to the potential for being disconnected from natural gas?
  - What kind of questions or concerns arise for you? **BUILD LIST OF CONCERNS**

What energy sources would you want to shift to? Or have the option to shift to? robe: electricity? Or something else?

Section 4: Incentive Offer

(Time: 30 minutes)

Let's talk a little bit more about those questions and concerns. **(ROTATE ORDER OF EQUIPMENT AND COSTS / FOLLOW DISCUSSION FLOW)**

Operating Costs:

- What types of costs do you consider? **(IF NOT ALREADY MENTIONED, LISTEN FOR OPERATING COSTS)**
- When you consider the operating costs of the equipment (i.e. your current electricity and natural gas bill compared to the future electricity bill), is there anything that concerns you?
  - What would be a fair offer to compensate you? For how long should this be factored in?
  - What about other ways to help you reduce your operating costs?
- Is there anything else that comes to mind in terms of what should be considered in the offer?

Equipment and Installation:

- How easy or difficult would you think it is to replace the natural gas equipment in your home with a non-natural gas alternative? What makes you say so?
- What would be a fair offer from Enbridge Gas to help you replace your equipment? **(SOLICIT IDEAS)**
    - What would a fair offer to you specifically? / What would help you agree to the disconnection?
- **(IF NOT ALREADY MENTIONED)** What about the following …
    - What do you think about the replacement of your natural gas equipment or appliance with an electric option? Or another energy source?
    - Should Enbridge offer all customers a standard, basic, electrical (or other energy source) option for replacement or should Enbridge consider a like-for-like replacement option?
    - **PROBE ON SPECIFIC TYPES OF EQUIPMENT IF NOT ALREADY MENTIONED:**
        - Home heating (furnace or boiler)
        - Fireplace
        - Water heating
        - Cooking
        - Clothes Dryer
        - BBQ
        - Pool heater
        - Any other equipment?
    - Are there any pieces of equipment where you are more concerned about the replacement options available compared to others?
    - For any of these, is there anything specifically that you would expect to be offered as an alternative? Or not offered?
    - What if the equipment is rented? How should that be considered? Buy-out of the contract? Change of the agreement?
    - What about installation costs?

Section 5: Incentive Mechanism

(Time: 30 minutes)

(IF NOT ALREADY IDENTIFIED) How do you think that the replacement options, or alternatives to your natural gas equipment, we discussed should be handled, or provided to customers? **SOLICIT IDEAS/BUILD LIST**

In all cases, Enbridge Gas technicians will remove the natural gas services at the home.

When it comes to installing replacement technology, What makes the most sense to you? (ROTATE OPTIONS)

- Enbridge Gas provides you with a check and you to handle the next steps yourself?
- Enbridge Gas provides you with a service provider that would change out all your equipment?
- Or something else in between?

Would your opinion change if you had to pay for part of the cost? [REFERENCE PREVIOUS DISCUSSION]

Would you be more or less supportive of this initiative if Enbridge supported your participation in an energy savings program, to help make your home more energy efficient (and address the operating cost issue … more insulation, weatherproofing, windows and doors replacements, etc.)? Or would it not make a difference?

Is there anything else that comes to mind in terms of what should be considered in how the offer is delivered?

Section 6: Other concerns

(Time: 10 minutes)

(IF NOT ALREADY MENTIONED):

- Is there anything else that we haven't already talked about that you see as a potential opportunity or concern if a home would be disconnected from natural gas?
- Do you think there will be any impact on the value, or future resell value, of your home?
- **[OPTIONAL IF TIME PERMITS:]** If Enbridge Gas wanted to better understand the implications of a project like this, and would want to understand electricity use before and after disconnection, do you think it would be reasonable for customers to provide access to electricity usage or past and future electric bills?

(Optional Section) Marketing / Communications (Time: 10 minutes – if time allows)

- How do you think Enbridge Gas should first communicate a system pruning pilot project to the homeowners, or community, that may be part of the area? (Probe: door-to-door, in-person, email, letter, open house, etc.)
- Where and how would you want to see or receive more information? (Probe: door-to-door, in-person, email, letter, open house, online, etc.)

Who would you want this information from? (Probe: Enbridge Gas employees, contractors suggested by Enbridge or your own selected contractor, independent third-party or consultants)

Section 7: Final Thoughts?

(Time: 10 minutes)

Before we wrap up, let me ask this. Is there anything we missed that you think Enbridge Gas should be considering when it is looking at this pilot? COLLECT COMMENTS

Thank you for joining us tonight. Contact info reminder.

APPENDIX

Note for moderator only; this won't be shown to the customers during the discussion.

Type	Typical Equipment (Natural Gas)	Alternative Electric Solution	Details
Home Heating	Forced Air Furnace	Air Source Heat Pump (ASHP) or Cold Climate ASHP	High-efficiency ASHPs can operate effectively in sub-zero temperatures, providing both heating and cooling.
	Boiler (Hydronic System - Radiators/In-floor Heating)	- **Air-to-Water Heat Pump (AWHP)**	AWHPs supply hot water for hydronic systems, providing an efficient electric alternative to gas boilers.
		- **Mini-Split Heat Pump**	Mini-splits provide direct room-by-room heating and cooling, bypassing the hydronic system entirely.
Water Heating	Tank Water Heater	Electric Heat Pump Water Heater (HPWH)	HPWHs use ambient air to heat water, reducing energy consumption by up to 70% compared to gas water heaters.
	Boiler Combo Unit (Space + Water Heating)	Air-to-Water Heat Pump (AWHP)	AWHPs can replace combo systems, heating water for both space heating (hydronic) and domestic use.

Notes on Mini-Split Heat Pumps:

- **Advantages:** Mini-split heat pumps are easier to install than retrofitting an entire hydronic system for a heat pump. They offer zoned heating and cooling, which can improve energy efficiency and comfort.
- **Limitations:** They operate independently from the existing hydronic system, so radiators or in-floor heating would no longer be the primary heat source. Homeowners may need multiple indoor units for full coverage.
- **Applications:** Mini-splits are particularly useful when a partial electrification solution is desired, or when hydronic retrofitting is too complex or costly.

2025 System Pruning Pilot
Customer Survey

Subject: Enbridge Gas is looking for your feedback!

Dear [FULL NAME FROM SAMPLE],

Enbridge Gas wants to hear from customers like you in its business planning process. The goal of this survey is to understand what is valued by customers like you so it can be considered when making key business decisions.

For this survey, we would like to hear from someone in your household who is responsible or jointly responsible for decisions regarding natural gas and the equipment in the home. If that is not you, please forward this email to the appropriate person.

This survey will take approximately 15-20 minutes to complete, and if you're unable to complete it in one session, you can pick up where you left off by clicking the survey link again – your progress will be saved. We kindly ask that you complete the survey by clicking the link below.

Start Survey

To ensure all responses are kept anonymous and confidential, all survey responses will be collected by INNOVATIVE Research Group, an independent market research company. If you would like to verify the authenticity of this survey or would like more information about the survey, you can contact marketresearch@enbridge.com.

If you have any problems with the above link, please copy and paste the following address into your web browser.

Survey Link: >>>>

Thank you for your time and input into this planning process.

Enbridge Gas Inc.

Contact Us | Privacy Policy

Any feedback you provide will be kept strictly confidential. If you experience technical issues with this survey, please reply directly to this email. For all other inquiries, please use the Contact Us link.

If you do not wish to receive further survey invitations from Enbridge Gas, please click here to unsubscribe.

Enbridge Gas Inc. | www.enbridgegas.com | 500 Consumers Road, North York, ON, M2J 1P8

Customer Survey

Screener

We would first like to ask you some questions to get started.

NTD: The purpose of this section would be to make sure we are completing the survey with the right individual.

Q1. Do you own or rent your primary residence?
[SINGLE SELECT]

01	Own	
02	Rent	**TERMINATE**
98	Don't Know	**TERMINATE**

Q2. Are you involved in making energy-related decisions, including decisions about home and water heating equipment as well as other major appliances, that impact your household?
[SINGLE SELECT]

01	Yes, I am the sole decision maker	
02	Yes, I make decisions in partnership with someone else (i.e., spouse, partner, etc.)	
03	Yes, I influence the decision but someone else makes the final decision	
04	No, I do not influence these decisions	**TERMINATE**
98	Don't know	**TERMINATE**

Q3. Which of the following best describes your primary residence?
[SINGLE SELECT]

01	Single detached house	
02	Semi-detached house	
03	Row or Townhouse	
04	Low rise apartment building (4 stories or less)	**TERMINATE**
05	Duplex or triplex	**TERMINATE**
06	High rise apartment building (greater than 4 stories)	**TERMINATE**
88	Other – (please specify) _____	**TERMINATE**
98	Not sure	**TERMINATE**

Q4. Do you, or does anyone else in your immediate family work in any of the following areas?
Select all that apply.

01	Marketing research	**TERMINATE**
02	Energy providers, such as natural gas, oil, electricity, propane	**FLAG AS SECTOR PARTICIPANT**
03	Renewable energy provider, such as solar energy, wind power, or other	
04	A home heating equipment or appliance contractor or retailer	
05	An insulation contractor or retailer	
06	Energy sector regulator or intervener, government ministry or agency involved in energy policy	
97	None of the above	**MUTUALLY EXCLUSIVE**

TERMINATE LANGUAGE – Thank you for your interest in the survey. The rest of the survey is not applicable.

Introduction

Enbridge Gas is continually working on its business plan for its assets and would like to hear your feedback on a part of this plan, which includes a new pilot project.

It is important to Enbridge Gas that its projects are informed by customer needs and preferences. This is a preliminary survey to make sure that this pilot project is informed and refined by customer feedback.

We will share more details about this project through the questions in this survey and look forward to your feedback.

Please note that the project and related offers described in this survey are in the preliminary stages of development and finalized project and offer details will be communicated to affected customers through direct communications from Enbridge Gas at the time of implementation.

Near the end of this survey, you will have the opportunity to provide any additional comments that you would like to share with Enbridge Gas.

All individual responses will be kept confidential. Innovative Research Group (INNOVATIVE), an independent research company, has been hired to gather your feedback.

Throughout this survey, if you aren't sure what your response is, please indicate this. Thank you in advance for your feedback and participation!

Current natural gas equipment

NTD: The purpose of this section would be to understand current equipment the customer has. This will help to understand the impact of disconnection for the customer.

We would like to understand how you are currently using natural gas in your home.

Q5. How do you primarily generate heat in your home?
Please review the options carefully.
[SINGLE SELECT]

01	Air source, or electric, heat pump *(Note: this means you have a heat pump that uses electricity to generate heat, and may have a furnace for the distribution of that heat, we'll ask you about any backup equipment you may have in the next question)*
02	Ground source heat pump, also known as electric geothermal
03	Natural gas furnace *(Note: don't select this option if you have a heat pump)*
04	Natural gas boiler or hot water radiator
05	Natural gas fireplace for primary home heating
06	Oil furnace
07	Electric furnace
08	Electric baseboards
09	Propane heating
10	Natural gas heat pump *(Note: this means you have a heat pump that uses natural gas to generate heat)*
88	Other: _____
98	Don't know

SHOW ON SAME PAGE AS Q5 (DUE TO CUSTOMER CONFUSION ABOUT EQUIPMENT)
IF AIR SOURCE, OR ELECTRIC, HEAT PUMP [ASK IF Q5 = 01]

Q6. Do you have any other home heating equipment as a backup to your heat pump, and if so, what kind of equipment do you have? *Select all that apply.*

01	Natural gas furnace	
02	Natural gas boiler or hot water radiator	
03	Natural gas fireplace	
04	Electric furnace	
05	Electric baseboard	
06	Electric boiler or hot water radiator	
07	Electric fireplace	
88	Something else not listed here: _____	
97	No, I don't have any backup home heating	**MUTUALLY EXCLUSIVE**

Q7. Do you use natural gas for any of the following in your home? *Please select all that apply*.

01	Natural gas fireplace for supplementary home heating or ambiance
02	Hot water / water heating
03	Cooktop / Stove / Oven
04	BBQ
05	Clothes dryer
06	Pool heater
07	Generator
88	Or do you use natural gas for anything else: _____
98	Don't know

Q8. Based on what you know today, when would you approximately expect you would be replacing or upgrading your equipment? If needed, please share your best guess.

LIST ALL NG EQUIPMENT SELECTED FROM Q5 (=03,04,05,10), Q6 (=01,02,03) AND Q7 (=ALL SELECTED EXCEPT 98) SHOW IN TABLE FORMAT

01	Within the next 1-2 months
02	Within the next 3 to 12 months
03	1 year to 2 years from now
04	3 to 5 years from now
05	6 to 10 years from now
06	10 or more years from now
98	Don't know

Explaining IRP and System Pruning

NTD: Understand current awareness of IRP and reactions to the System Pruning pilot project.

SHOW DESCRIPTION:

Enbridge Gas has many kilometers of pipelines in the ground in Ontario to deliver natural gas to its customers. It maintains, replaces, and expands parts of this pipeline network to meet customer needs with approval from the Ontario Energy Board (OEB). The OEB regulates natural gas utilities in Ontario and approves the rates charged to customers.

Q9. Before today, were you aware of the OEB and its role?

01	Yes, I was aware and could explain its role in detail to others
02	Yes, I was aware, but could not explain its role in detail to others
03	No, I was not aware
98	Don't know

Over time, pipelines wear out and need replacing. Pipeline projects can vary greatly in cost, due to materials, labour, and changing requirements for construction to protect environmentally sensitive areas and reduce inconvenience in built-up areas.

When considering any pipeline replacements, Enbridge Gas must evaluate whether other options are available that could either delay, reduce, or eliminate the need for work on the pipelines at a lower cost and/or lower environmental impact.

Q10. Based on this information, do you think it makes sense for Enbridge Gas to look at other options before replacing older pipelines?

01	Yes, they should consider other options where it makes sense from an economic, technical, and environmental perspective
02	No, they should just replace pipelines that are at the end of their useful life
98	Don't know

SHOW DESCRIPTION:

There is an option that could be considered for pipeline replacement projects.

This option would apply to a single street, or a smaller area and considers disconnecting customers and removing the pipeline *instead of* replacing it.

This option would only be considered if everyone agrees, voluntarily, to disconnect.

Customers who agree to disconnect would shift to other energy sources, such as electricity, to fuel their equipment and appliances. Instead of money being spent on replacing the pipelines, money can be used to support the disconnection process and provide affected customers with the replacement equipment they would need.

Enbridge Gas would work with the local electric utility to ensure that sufficient electrical supply was available to support customer upgrades that might be required.

Q11. Based on this information, do you think it makes sense for Enbridge Gas to consider this option?

01	Yes, they should consider this option where it makes sense from an economic, technical, and environmental perspective as long as all customers in the area voluntarily agree to disconnect
02	No, they should just replace pipelines that are at the end of their useful life
98	Don't know

Testing the Customer Offer

The description indicated "Instead of money being spent on replacing the pipelines, money can be used to support the disconnection process and provide affected customers with the replacement equipment they would need."

(SHOW BASE OFFER FIRST AND RANDOMIZE OTHER OFFER SECTIONS – SHOW KITCHEN INCIDENTALS FIRST, OVERALL INCIDENTALS LAST, AND ENERGY BILL + DSM TOGETHER IN THIS ORDER

Base offer

We'll now look at a potential offer that could be made to help customers with the transition away from natural gas and to facilitate the disconnection.

The offer would include the following, at no cost, to the affected customers:

- ✓ Removal of the natural gas meter and pipelines on the property
- ✓ Removal of natural gas equipment and appliances in the home (or elsewhere on the property, as applicable)
- ✓ Installation and all equipment costs for new replacement electric (or alternative fuel) equipment based on the closest equivalent or available option (in terms of size and features)
- ✓ Necessary upgrades to the electrical service (for example, electrical panel upgrades)

	Most common replacement option *(subject to review with the homeowner)*
Natural Gas Furnace	Cold climate air source heat pump with electric backup
Natural Gas Boiler / Hydronic System	Air to water heat pump with electric backup
Natural Gas Water Heater	Heat pump hot water heater or electric water heater (tank or tankless)
Natural Gas Cooktop / Stove	Induction stove (same number of burners)
Natural Gas Oven	Electric oven
Natural Gas Fireplace	Electric fireplace
Natural Gas Clothes Dryer	Electric clothes dryer
Natural Gas Barbecue	Propane BBQ
Natural Gas Pool heater	Air source heat pump for pool

Regardless of the age of the current equipment, the replacement equipment would be new. Appliances and equipment with an ENERGY STAR® rating or equivalent would be installed.

The cost for the project, whether a pipeline or an alternative option, is shared by all rate payers in Ontario.

To ensure all Enbridge Gas rate payers benefit, this approach would only be used where/when the cost of helping customers get off the natural gas system, through the potential offer made, is lower than the cost of investing in new natural gas pipeline infrastructure.

Q12. Considering the specific elements of this offer, how fair would you say this offer is?

01	Very fair
02	Somewhat fair
03	Not very fair
04	Not at all fair
98	Don't know

Q13. Why do you feel that way?

01	**[OPEN]**
98	Don't know

Q14. If this project were happening in your area, based on this offer, how likely would you be to agree to participate and disconnect?

01	Definitely likely
02	Somewhat likely
03	Not very likely
04	Not at all likely
98	Don't know

Q15. What, if anything, would you change to make this offer better?

01	**[OPEN]**
97	I would not change anything
98	Don't know

There are some additional elements to the offer that you may have already mentioned or that could be considered. Please consider each of these elements and share your thoughts on whether you think these should be considered as part of the offer that would be made to customers if Enbridge Gas were to look at an alternative option to a pipeline project.

As indicated such a project would only be considered where it makes sense from an economic, technical, and environmental perspective, and if all customers were to voluntarily agree.

Q16. In terms of the work that is described above, which of the following would be your preferred approach?

01	Enbridge Gas should have a reputable contractor complete the equipment replacement and all the required work in the home; or

02	Enbridge Gas should offer the required funds so that the homeowner can select a contractor from a list of qualified contractors to complete the work within a required period of time; or
88	Something else? **[PLEASE SPECIFY]**
98	Don't know

OFFER: Kitchen Incidentals Offer

ASK ONLY IF THEY HAVE A NATURAL GAS COOKTOP/STOVE OR OVEN (Q7 = 03)

Q17. When it comes to replacing natural gas cooking equipment, with an electric option, this may require some additional funds to manage the cabinetry, cookware, or other changes in the kitchen.

What do you think is a reasonable amount of additional funds, if any at all, to be included in the offer to cover this?

ROTATE HIGH TO LOW / LOW TO HIGH

01	$500
02	$750
03	$1000
04	$2000
88	Something else? **[PLEASE SPECIFY]**
97	Don't include this in the offer, it is not necessary
98	Don't know

OFFER: Upgrade Equipment Offer

Q18. If a customer is interested in potential upgrades, for example increasing the size of their water heater, changing their cooktop/stove, or choosing a higher-end option, Enbridge Gas could make this available, with the extra costs to be paid for by the customer.

In your opinion, does adding this option make the offer better or worse?

01	Definitely better
02	Somewhat better
03	The same
04	Somewhat worse
05	Definitely worse
98	Don't know

OFFER: Energy costs offer

A home's total energy bill includes the costs of the energy sources used in the home – natural gas, electricity, propane, or anything else that might be used. It includes fixed customer costs, energy usage, taxes and subsidies.

Q19. When you think about the total bill, on average, over the course of the year, do you think that it will change as a result of a disconnection from natural gas?

01	Yes, I expect the total energy bill will increase
02	No, I think the total energy bill will remain the same
03	Yes, I think the total energy bill will decrease
98	Don't know

ASK NEXT QUESTIONS (Q20 & Q21) IF Q19 = 01, OTHERWISE GO TO NEXT OFFER:

Q20. Since the total energy bill may vary because of the change in equipment, but also because of other influences on the price, how do you think disconnected customers should be compensated for this if the total energy bill increased because of this project?

01	A variable payment based on the change in the energy costs over a period of time – this would be a no bill increase guarantee	
02	Offer a lump sum payment at the time of disconnection to cover the likely increase	
88	Something else? **[PLEASE SPECIFY]**	
97	Don't include this in the offer, it is not necessary	**SKIP TO Q22**
98	Don't know	

DO NOT ASK Q21 IF Q20=97

Q21. Thinking again about compensation for an increase, if there is one, in a household's total energy bill, what is a reasonable amount of time that the increase in the total energy bill should be reviewed and compensated for?

ROTATE HIGH TO LOW / LOW TO HIGH

01	One year
02	Two years
03	Three years
04	Five years
88	Something else? **[PLEASE SPECIFY]**

OFFER: Energy Efficiency Offer

One option to reduce the total energy bill would be to look at ways to improve the energy efficiency of the home as part of the offer. This would include a visit to the home by a registered energy auditor who would be able to provide recommendations on ways to improve the energy efficiency of the home. Implementing these recommendations could help address the total energy bill.

Recommendations could include:

- ✓ Weatherstripping, or air sealing to reduce air leakage from the home;
- ✓ Add insulation in the home (attic, wall, foundation, exposed floor);
- ✓ Upgrade windows and doors; or
- ✓ Install a smart thermostat

The Home Renovation Savings Program currently offers rebates and incentives for these recommendations, and the offer could include elements of this program.

Q22. How do you think this should be included in the offer?

01	This disconnection offer should include information to encourage customers to participate in this renovation program, or any other programs that are available at the time	**SKIP TO NEXT OFFER**
02	This offer should include additional top-ups, with higher incentives	
88	Something else? **[PLEASE SPECIFY]**	**SKIP TO NEXT OFFER**
97	Don't include this in the offer, it is not necessary	**SKIP TO NEXT OFFER**
98	Don't know	**SKIP TO NEXT OFFER**

ASK IF Q22=02 (HIGHER INCENTIVES)

Q23. What is a reasonable incentive level that you think would need to be included as part of the offer?

ROTATE HIGH TO LOW / LOW TO HIGH

01	30% of the total cost
02	50% of the total cost
03	75% of the total cost
04	100% of the total cost
88	Something else? **[PLEASE SPECIFY]**
98	Don't know

OFFER: Extended Warranty Offer

Q24. If Enbridge Gas were to offer, through the contractor completing the work, an extended warranty on the equipment, with the extra costs to be paid for by Enbridge Gas, in your opinion, would this option make the offer better or worse?

01	Definitely better
02	Somewhat better
03	The same
04	Somewhat worse
05	Definitely worse
98	Don't know

OFFER – ALWAYS ASK LAST: Incidentals / Additional Incentive

Q25. When it comes to the overall disruption and inconvenience that would come with a project like this, what do you think is a reasonable amount that should be offered? This amount could help to offset any costs if someone had to take a day off work during the equipment change, cover any small fix-ups in paint, or trim, or other incidentals, as needed.

ROTATE HIGH TO LOW / LOW TO HIGH

01	$300	

02	$500	
03	$1000	
04	$1500	
88	Something else? **PLEASE SPECIFY**	
97	Don't include this in the offer, it is not necessary	
98	Don't know	

Q26.

Anything else?

Q27. Now that we have looked at some offer options in more detail, is there anything that you would expect to see as part of the offer that has not been asked about? What would that be?

01	**[OPEN]**
97	No, I have nothing to add
98	Don't know

Q28. Considering what you have seen about the offer that would help affected customers to disconnect, and the choices you have been making, if this project were happening in your area, and all the offer elements you chose or suggested were included, how likely would you be to agree to participate and disconnect?

01	Definitely likely
02	Somewhat likely
03	Not very likely
04	Not at all likely
98	Don't know

Q29. If this project were happening in your area, would there be anything else that you would need to know more about to help make the decision to agree to participate and disconnect?

01	**[OPEN]**
98	Don't know

Q30. Some have suggested that a project like this may affect the value of their home. If this project were happening in your area, considering both the disconnection from natural gas and the new equipment that would have been installed as a result, how do you think that this would affect the sale value of your home?

RANDOMIZE ORDER OF 1 TO 3 and 3 TO 1

01	The disconnection from natural gas would decrease the sale value of my home
02	The disconnection from natural gas would have little to no impact on the sale value of my home
03	The disconnection from natural gas would increase the sale value of my home
98	Don't know

Overall Attitudes and Perceptions

NTD: The purpose of this section would be to understand which attitudes or perceptions impact the results of the survey.

You will now see a list of statements related to energy topics, please read each statement carefully and indicate your level of agreement with each statement.

01	Strongly agree
02	Somewhat agree
03	Neither agree or disagree
04	Somewhat disagree
05	Strongly disagree
98	Don't know

[RANDOMIZE]

Q31. **[OVERALL CLIMATE CHANGE CONCERN]** I am extremely concerned about climate change

Q32. **[ELECTRIFICATION PROVINCE]** Eliminating the use of natural gas today would have a negative impact on Ontario's economy

Q33. **[ELECTRIFICATION HOME]** Eliminating the use of natural gas from my home and replacing it with electricity would have little to no impact on my quality of life

Q34. **[FIRST ADOPTER]** I am usually the first among my friends to adopt a new technology

Q35. **[TRUST]** I prefer to do my own in-depth research when it comes to making decisions for my household

Q36. **[CHOICE]** It is important to me to have options to choose the type of energy I use, so that I have choice in terms of cost or the appliances I have now or would like to use in the future

Q37. **[POCKETBOOK]** The cost of my Enbridge Gas bill has a major impact on my finances and requires I do without some other important priorities

Q38. **[OVERALL ENERGY SYSTEM]** Customers are well served by the energy system in Ontario

[END BATTERY]

Q39. Generally speaking, what is your impression of natural gas as an energy source?

01	Very favourable
02	Somewhat favourable
03	Neither favourable nor unfavourable
04	Somewhat unfavourable
05	Strongly unfavourable
98	Don't know

Q40. How satisfied are you with the reliability – lack of interruptions or outages – of the electricity provided to your home, overall?

01	Very satisfied
02	Somewhat satisfied
03	Not very satisfied
04	Not at all satisfied
98	Don't know / not sure

Additional Comments

Q41. Is there anything you would like to share with Enbridge Gas about the topics in this survey?

01	**[OPEN]**
98	Don't know

Demographics

Now we would like to ask you some questions about yourself. This will help us to analyze the results of the survey and ensure that we have a representative sample of the population. All your answers will be kept confidential and used only for statistical purposes.

Q42. In what year was your house built?

01	Before 1900
02	1900-1949
03	1950-1959
04	1960-1969
05	1970-1979
06	1980-1989
07	1990-1999
08	2000-2009
09	2010-2019
10	2020-2022
11	2023-2025
98	Don't know

Q43. What is the approximate size of your house? *Please include your basement if it is greater than 6 square feet (0.5 Sq. Meters) in size.*

01	Less Than 1000 Square Feet (93 Sq. Meters)
02	1000 To 1499 Square Feet (94 To 139 Sq. Meters)
03	1500 To 1999 Square Feet (140 To 185 Sq. Meters)
04	2000 To 2499 Square Feet (186 To 232 Sq. Meters)
05	2500 To 2999 Square Feet (233 To 278 Sq. Meters)
06	3000 Square Feet Or More (279 Sq. Meters Or More
98	Don't know

Q44. Do you have any plans to sell your home in the next 2 years?

01	Yes, definitely planning on it
02	Maybe, considering it or looking into it
03	No
98	Don't know

Q45. Including yourself, how many people in total live in your household?

01	**[RANGE 1 - 100]**
97	Prefer not to answer

Q46. What is your age?

01	**[RANGE 1 - 200]**
97	Prefer not to answer

IF Q46=97 PREFER NOT TO ANSWER

Q47. Into which of the following age categories do you fall?

01	18 to 24
02	25 to 44
03	45 to 64
04	65 to 74
05	75 or older
97	Prefer not to answer

Q48. Which of the following best describes your total annual household income (after taxes)?

01	$39,999 or less
02	$40,000 to $59,999
03	$60,000 to $79,999
04	$80,000 to $99,999
05	$100,000 to $124,999
06	$125,000 to $149,999
07	$150,000 and over
97	Prefer not to answer

Q49. Are you an Indigenous person, that is First Nations (North American Indian), Métis or Inuk (Inuit)? *Please select all that apply*.

01	No, not an Indigenous person
02	Yes, First Nations
03	Yes, Métis
04	Yes, Inuk (Inuit)
98	Don’t know
97	Prefer not to answer

Q50. How would you best describe your current employment status?

01	Working full-time
02	Working part-time
03	Self-employed
04	Retired
05	Unemployed, but looking for work
06	Student
07	Not in workforce (i.e. homemaker/ unemployed, not looking for work)
88	Other
97	Prefer not to say

Thank you for completing our survey today!

As indicated, this survey is an important tool that Enbridge Gas uses to make sure that its customers' needs and preferences are being considered as it develops its plans. This survey is not an indication that you will be disconnected from natural gas and Enbridge Gas looks forward to continuing to serve you.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

2025 IRP Report [G/2/1, page 22])

Interim report	Once	NA	Q2 2026	
Final report	Once	NA	Q4 2027	The timing has shifted to allow for sufficient time to explore DR events that end Q1 2027

Question(s):

a) Please explain why there is 1.5 year difference between the schedule for the Interim SLH Pilot Project Report and the Final Report.

b) Please confirm that the SLH Pilot Project is on track against the schedule noted above. If not, what milestone dates are currently impacted.

c) What are the annual and total SLH IRP Pilot costs and please provide the reference to where any of those costs have been embedded in a variance account for current or future clearance.

Response:

a) Southern Lake Huron (SLH) Pilot Project Objective 2 is to develop an understanding of how to design, deploy, and evaluate enhanced targeted energy efficiency (ETEE) and residential demand response programs.

The SLH Pilot Project Objective 2 Interim Report outlines early findings and insights gained through Objective 2 evaluation activities conducted up to that point. This includes early-stage interviews with implementers, contractors, and energy advisors, as well as interviews with a few early participants. A key focus of the report is to identify early insights for further exploration in more detail within Objective 2 interview/survey activities that will be conducted over the remaining term of the evaluation of the SLH Pilot Project.

The SLH Pilot Project Objective 2 Final Report will cover findings from the full suite of all Objective 2 activities. This includes survey and interview activities expected in

Q1 2027 following the conclusion of participation in the ETEE offerings at the end of 2026, as well as evaluation activities in Q2 2027 for the residential demand response offer that ends at the close of Q1 2027. The Final Report will be completed following an analysis of all evaluation activities.

b) Confirmed, the SLH Pilot Project is on track. Consistent with the nature of the "Notes" column in this table, the cadence of evaluation activities will continue to be adjusted as required as the Pilot Project continues, ensuring that the objectives are met.

c) Please see Exhibit C, Tab 2, Schedule 24, pages 7-8 for the annual and cumulative SLH IRP Pilot Project costs and associated deferral accounts for future clearance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

Interrogatory

Reference:

2025 IRP Report

Question(s):

a) The 2025 IRP Report does not appear to have any progress noted for the second IRP Pilot Project. Please provide an update of the status on the second IRP Pilot Project and what the current total costs are.

b) When does Enbridge plan to clear costs related to the second IRP Pilot Project?

Response:

a-b) Any additional pilot project(s) will be considered as part of the Integrated Resource Planning (IRP) Framework Review proceeding. This follows the direction in the OEB Decision and Order for the Motion to Review Decision on IRP Pilot Project, which stated:

> The OEB does not consider it efficient or cost-effective to have Enbridge Gas and TWG members begin discussions on a second pilot project in parallel with the IRP Framework Review. The OEB agrees with OEB staff that matters related to further IRP pilot projects are best considered as part of the IRP Framework Review, and the OEB expects that matters related to a second IRP pilot project and any further IRP pilot projects will be addressed as part of the IRP Framework Review.[1]

[1] EB-2025-0333, Decision and Order, May 14, 2026, p.17.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

B-1-3

Question(s):

Please identify all changes in the methodology used to calculate utility earnings for earnings sharing purposes, as compared to the last year in which earnings sharing applied, excluding any allocation methodologies explicitly approved in EB-2022-0200 or EB-2024-0111. For each change, please provide details and the impact on the 2025 earnings sharing amount.

Response:

There are no changes noted between the methodology used to calculate utility earnings for earnings sharing purposes in the 2023 Utility Earnings and Disposition of Deferral & Variance Account Balances application[1] (the last year in which earnings sharing applied) and 2025 Utility Earnings and Disposition of Deferral & Variance Account Balances application[2].

[1] EB-2024-0125,
[2] EB-2026-0108.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

B-1-1, p.4

Question(s):

With respect to the identified depreciation error:

a) Please provide further explanation of the depreciation error and provide the specific calculations of the $14.5M in 2024 and $2.8M in 2025.
b) Is the identified depreciation error, reflected in the 2024 depreciation expense and rate base, approved in EB-2022-0200? If yes, provide the amount included in rates for each year from 2024 to 2028. If not, please explain why not.
c) Please reconcile the depreciation amount of $765.4M in the Continuity of Accumulated Depreciation schedule (B-1-5, p.4, Col 2, Ln. 50) with the depreciation and amortization expense of $763.8M included in Utility Income (B-1-3, p.1, Col. 4, Ln. 9).

Response:

a) Enbridge Gas recognized depreciation expense in 2024 and 2025 on software assets whose NBV had been fully impaired as of December 31, 2023 in accordance with the OEB Decision and Order from EB-2022-0200 Phase 1[1]. The error was not a result of a calculation error. Following the December 2023 impairment recorded at the general ledger level, subsequent processing of the impairment through the fixed asset subledger in 2024 generated depreciation expense that was not fully reconciled to the intended impairment accounting treatment, resulting in the over-depreciation of $14.5 million in 2024 and $2.8 million in 2025. Please Table 1 for the continuity of accumulated depreciation for Acct #491 - General Plant – Software Acquired/Developed before and after the correction of the error:

[1] EB-2022-0200, Interim Rate Order, April 11, 2024, Overview, pp. 3-4.

Table 1
Accumulate Depreciation Continuity for Acct 491 – Software Acquired/Developed

Line No.	Particulars ($ millions)	Opening	Depreciation/ Adjustments-Other	Retirements	Closing
	Acct 491 - Software Acquired/Developed:				
1	2024 (includes error)	(68.4)	(24.7)	7.2	(85.9)
2	2025 (includes error)	(85.9)	(18.5)	24.0	(80.4)
3	Q1 2026 Adjustment[2]	(80.4)	17.3	-	(63.1)

The correcting journal entries in Q2 2026 upon discovery of the error reclassified the over-depreciation as an adjustment to 2024 and 2025 accumulated amortization, ensuring that depreciation expense through the end of 2025 in rate base reflects only the remaining assets with recoverable net book value and aligns financial reporting with the regulatory decisions.

b) No, the integration assets were not included in 2024 rate base, therefore they were not part of approved depreciation expense.

c) The Continuity of Accumulated Depreciation schedule includes depreciation adjustments and true-ups recorded in Column 6, "Adjustments & Other." When the ($1.5) million total adjustment in Column 6 is combined with the Column 2 depreciation amount of $765.4 million, total depreciation expense is approximately $763.9 million, which agrees to the depreciation and amortization expense reflected in the Utility Income schedule.

[2] Adjustment of $17.3 million includes opening 2025 balance adjustment for 2024 error of $14.5 million plus removal of $2.8 million of depreciation error in 2025.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

B-1-4, p.2

Question(s):

With respect to the Tax Variance Account, please explain why $498.3M of capital additions does not qualify for the RIIP. Please provide the explanation by CCA class and the criteria Enbridge applied.

Response:

The $498.3 million does not qualify for Reaccelerated Investment Incentive Property (RIIP) treatment because those capital costs were incurred prior to January 1, 2025, notwithstanding that the associated assets were placed in service in 2025. In determining eligible additions, Enbridge Gas applied the RIIP criteria to capital costs that were both incurred after December 31, 2024 and associated with property placed in service before the end of 2025. As a result, costs incurred in 2024 were not treated as RIIP-eligible additions when the related assets subsequently entered service in 2025.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

C-2-3

Question(s):

With respect to the UFG Volume Variance Account:

a. Please provide a version of Table 1 from EB-2025-0155 Interrogatory Response I.Staff-1 for 2025, and also an updated version for 2024.
b. Please provide an update to the table included in EB-2025-0155 Interrogatory Response I.EP-1to include 2025 data.

Response:

a) Please see the response at Exhibit I.STAFF-1 part a) for 2025 UFG contributing sources.

b) Please see Table 1.

Table 1
Historical UFG Volumes for EGI (Regulated)

Line No.	Particulars	UFG Volumes (10^3m^3)	Estimated Bills (1)
1	2013	199,833	
2	2014	225,027	
3	2015	137,110	
4	2016	250,923	
5	2017	190,881	
6	2018	266,362	
7	2019	263,407	
8	2020	177,291	
9	2021	342,549	2,177,164
10	2022	480,301	2,146,394
11	2023	192,110	2,081,710
12	2024	334,888	2,252,790
13	2025	370,109	2,103,369

Notes:
(1) inclusive of the bi-monthly expected estimates

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

C-2-20, Attachment 1

Question(s):

With respect to the Disposition of Property Deferral Account, for each property sold, please provide, a) details regarding the sale process, b) provide copies of any appraisals or valuations undertaken before the sale, c) justification for any material variance between sale price and appraisal/valuation, d) description of any building or other structures on the property, e) evidence to justify the allocation of costs between land and building, including any third-party analysis, and f) whether the purchaser is an affiliate of Enbridge.

Response:

See below:

Brampton

Enbridge Gas was approached to sell a 1,669 sq. ft. parcel along its property line adjacent to Steeles Avenue to facilitate roadway reconstruction and improvements in 2025. A purchase price of $32.00 per sq. ft., totaling $53,410, was negotiated. This transaction was deemed 100% land as only bare land was involved in the transaction.

Dryden

As the property located at 304 Kennedy Road was surplus to Enbridge Gas' operational requirements, it was listed for sale. Enbridge Gas retained Jones Lang LaSalle (JLL) to prepare a Broker Opinion of Value (BOV), which identified an average comparable sale value of $177,419 and recommended an asking price of $229,000, establishing a market range of approximately $175,000 to $230,000. Enbridge Gas subsequently agreed to sell the property for $209,000. The transaction closed in May 2025. The land versus building split of this transaction was determined to be 14.4% land and 85.6% building based on broker recommendations and observations of the property and market conditions.

Iroquois Falls

In February 2023, Enbridge Gas purchased an approximately 2-acre parcel of vacant land for $60,984. As part of the purchase agreement, Enbridge Gas covenanted to commence construction of an operations facility within two years of February 27, 2023. The agreement further provided that, if this condition was not satisfied, the seller would have the right to repurchase the property for 90% of the original purchase price. As capital priorities changed, Enbridge Gas had not commenced construction within the required period, and the seller exercised its repurchase right. The re-purchase closed on November 27, 2025, for $54,885. This property was traded as “bare land”, so it was deemed to be 100% land allocation.

Nipigon

As the property located at 2 Wadsworth Drive was surplus to Enbridge Gas’s operational requirements, it was listed for sale. Enbridge Gas retained JLL to prepare a BOV, which included input from a local Century 21 agent. Given the limited number of comparable commercial transactions in the market, JLL relied on available sales data, including a recent $216,000 sale of a car wash facility, and recommended a listing price of $239,900. The property was listed in April 2024. Following an extended marketing period and consideration of lower offers, Enbridge Gas agreed to sell the property for $200,000. The transaction closed in February 2025. The land versus building split of this transaction was determined to be 20% land and 80% building based on broker recommendations and observations of the property and market conditions.

Ottawa

As part of its broader asset strategy to consolidate the legacy Enbridge Gas and legacy Union Gas facilities into a single location, Enbridge Gas began exploring the sale of 400 Coventry Road in 2021. To support this effort, planning and design consultants were engaged to assess the site's development potential and the impact increased density could have on overall land value.

In April 2021, Enbridge Gas initiated work to understand the property’s potential given Transit-Oriented Development (TOD) designation, which would permit several high-rise residential towers with at-grade commercial development. Following these discussions and with a solid understanding of municipal requirements, Enbridge Gas elected to capitalize on strong market conditions for residential high rise development sites and formally marketed the property in September 2021.

After evaluating proposals from several parties, including structures that contemplated either a sale-leaseback arrangement or a delayed closing to allow for the relocation of employees to other facilities and, ultimately, the new Ottawa Regional Office on Lancaster Road, Enbridge Gas entered into an Agreement of Purchase and Sale in February 2022 for $20,000,000.

The agreement provided for an initial closing date of November 30, 2023, but was extended to May 13, 2025, when the transaction ultimately closed.

This transaction was assessed to be 100% land as the Purchase Price was derived out of the assessment of Highest and Best Use being that of redevelopment site and density value with the building and improvements being of no use.

St. Thomas

As the property located at 25 Sparling Road was surplus to Enbridge Gas's operational requirements, it was listed for sale. JLL prepared a BOV indicating a fair market value range of $1,320,000 to $1,760,000 and recommending a listing price of $1,600,000. JLL's valuation group also completed a formal appraisal in November 2024, concluding a market value of $1,400,000. Enbridge Gas agreed to sell the property for $1,600,000. The transaction closed in August 2025. The land versus building split of this transaction was determined to be 25% land and 75% building based on broker recommendations of the property and market conditions. However, this split was adjusted to 52% land and 48% building to account for the fact that the original assessment did not factor in the total land acreage including the value of the land under the building.

Stratford

As the property located at 827 Erie Street was surplus to Enbridge Gas's operational requirements, it was listed for sale. JLL prepared a BOV indicating a fair market value range of $1,960,000 to $2,260,000 and recommending a listing price of $2,400,000. JLL also completed a formal appraisal in November 2024 that concluded a market value of $2,100,000. Enbridge Gas agreed to sell the property for $2,000,000. The transaction closed in September 2025. The land versus building split of this transaction was determined to be 40% land and 60% building based on broker recommendations of the property and market conditions. However, this split was adjusted to 68% land and 32% building to account for the fact that the original assessment did not factor in the total land acreage including the value of the land under the building. See further details below.

In general, the market assumptions and valuations presented herein involve varying degrees of professional judgment, as several of the markets included in this analysis are relatively small and characterized by a limited number of comparable transactions from which fair market value can be reliably derived.

Additionally, the "Land/Building Split" is not a conventional real estate valuation metric and, as such, is inherently subjective. In many cases, it is intended to illustrate the relative contribution of surplus or redevelopment land value versus the value of the existing improvements, rather than representing a definitive allocation of total property value between the land and the buildings and other site improvements.

b and e) See Table 1:

Table 1
Details of 2025 Property Dispositions

Line No.	Property	BOV	Proposed Valuation ($ millions)	Sale Proceeds ($ millions)	Variance	Land/Building Split Rationale
1	Brampton	N/A[1]	N/A – negotiated	0.053	N/A	100% land, no building
2	Dryden	Based on comparable sales provided by broker, Attachment 1, p. 52	0.229	0.209	Not material	Broker recommended 14% land/76% building
3	Iroquois Falls	N/A[2]	N/A – as per re-purchase agreement	0.055	N/A	100% land, no building
4	Nipigon	Based on comparable sales provided by broker, Attachment 1, p. 53	0.040-0.216	0.200	Not material	Broker recommended 20% land/80% building
5	Ottawa	Attachment 1, pp. 13-51	13.935	20.000	Original BOV provided in 2019, market conditions improved significantly into 2025	BOV recommended best use as a redevelopment site, therefore allocated 100% land
6	St. Thomas	Attachment 1, pp. 1-6	1.320-1.760	1.600	Not material	Split adjusted after BOV to account for total land value[3]
7	Stratford	Attachment 1, p.7-12	1.960-2.260	2.000	Not material	Split adjusted after BOV to account for total land value[4]

[1] With regard to the Brampton property, as noted in a) above, Enbridge Gas was approached to sell and a sales price was negotiated. No BOV was requested.
[2] With regard to the Iroquois Falls property, as noted in a) above, the transaction involved the seller enforcing its re-purchase right, and therefore, no BOV was required.
[3] Land %: 2.29 total acreage x $400,000 per acre = $916,000 total land value / $1,762,400 total valuation = 52%
[4] Land %: 2.98 total acreage x $450,000 per acre = $1,341,000 total land value / $1,961,850 total valuation = 68%

c) As noted above, aside from the sale of the Ottawa location, there were no material differences between sale price and appraisal valuation; however, shifting economic environments did have an impact on some sales between the time a valuation was provided and the final sales price negotiated. These variances would have been impacted by changes in market conditions.

d) See below for further details of each property:

Brampton

No building or structures on the parcel of land sold.

Dryden

2000 square foot building on just over 1 acre of land. The property is a commercial /industrial building situated in a fully serviced industrial zone just off the Trans-Canada highway. The exterior of the building is a solid brick and metal structure featuring a large, paved parking apron and a separate storage shed. The building is divided into an office/boardroom area and an open shop/warehouse area.

Iroquois Falls

No building or structures on the property, this was a sale of vacant land.

Nipigon

There is a small approximate 1,400 square foot depot located at the property that has primarily served as a warehouse storage facility.

Ottawa

There was a three-story office complex attached to a single-story commercial/ industrial warehouse, however, the intention of the purchaser was to tear it down for a multi-family residential development.

St Thomas

This property has a 6,750 square foot building on 2.29 acres of land. The property is a freestanding commercial / light industrial building. The building has high clear heights and two drive-in bay doors.

Stratford

This property has a 6,996 square foot building on 2.98 acres of land. The property is a freestanding commercial and industrial building located within an established industrial and business corridor along Erie St. It includes two drive-in bay doors

designed to accommodate trade operations, equipment storage, and service vehicles.

f) None of the properties listed were sold to an affiliate of Enbridge Gas.

Pricing Guidance

MARKET AND VALUATION SUMMARY – ST. THOMAS INDUSTRIAL

25 SPARLING ROAD
ST. THOMAS, ON



EXECUTIVE SUMMARY

- The site is 2.29 acres with a 6,750 SF building with Employment Lands (EL) zoning that is fairly open and permits a broad range of commercial uses.
- Fair Market Value range is $1,320,000 to $1,760,000[1].
- JLL recommends pricing 25 Sparling Rd at $1,600,000 with a view to transacting closer to our high-end pricing illustrated in the table on the following page.

Split for accounting treatment

- Building to lot coverage is 6.6%, however building accounts for majority of property value, even after accounting for excess land.
- Excess Land Value is determined to range between $309,300 and $412,400. Building Value makes up the difference, ranging between $1,012,500 and $1,350,000[1].

[1] Using a price per SF of $150 – $200 based on recent comparable building sales, we value the building and underlying/adjacent land at between $1,012,500 and $1,350,000. Using a price between $300,000 and $400,00 per acre, we value the 1.031 acres of excess land between $309,300 and $412,400.

PRICING GUIDANCE

MARKET AND VALUATION SUMMARY – ST. THOMAS INDUSTRIAL

25 SPARLING ROAD
ST. THOMAS, ON

- The valuation for 25 Sparling Rd requires looking at the building in two components 1) the building with reasonably associated land and 2) the excess land for the property.
- Assuming a typical market lot coverage of 45%, the excess land component of the subject property has been calculated at 1.031 acres. Three vacant land properties were recently sold in the general vicinity of the subject property at 25 Sparling Road. The weighted average sale price for these properties was approximately $276,000 per acre and there are active listings for up to $500,000 per acre. There is considerable momentum for local industrial sector due to high profile new developments nearby (e.g. Amazon; Volkswagen EV) increasing speculation and driving rising property values. A value range of $300,000 - $400,000 per acre has been used for the purposes of this analysis.
- The combined suggested pricing of building and excess land would put the value of 25 Sparling Rd between $1,320,000 and $1,760,000.
- To achieve pricing in that price range we recommend listing the property at $1,600,000.

Valuation	Building size	Price PSF	Building Price (incl. land under building) (a)	Excess Land Size	Price per acre	Excess Land Price (b)	Total Site Price (a) + (b)
Low End	6,750	150	$1,012,500	1.031	$300,000	$309,300	$1,321,800
High End	6,750	200	$1,350,000	1.031	$400,000	$412,400	$1,762,400

Building Sales

MARKET AND VALUATION SUMMARY – ST. THOMAS INDUSTRIAL

25 SPARLING ROAD
ST. THOMAS, ON

Sale Comps

Property Address	City	Total Area (SF)	Office (SF)	Lot Area (Acres)	Zoning / Year Built	Sold Price	Sold Date
109 Gaylord Road	St. Thomas	13,500	NA	1.00	EL Circa 1980	$1,520,000	06/27/2023
107 Gaylord Road	St. Thomas	11,460	800	0.97	EL 1981	$1,650,000	01/18/2024
66 Progress Drive	St. Thomas	4,300	1,100	0.88	M2 2005	$1,313,000	01/10/2023

Available Buildings For Sale

MARKET AND VALUATION SUMMARY – ST. THOMAS INDUSTRIAL

25 SPARLING ROAD
ST. THOMAS, ON

Available Properties

Property Address	City	Total Area (SF)	Office (SF)	Lot Area (Acres)	Zoning / Year Built	Asking Price	Days on Market
6 Duckworth Avenue	St. Thomas	8,000	1,000 *(est.)*	0.70	EL unknown	$1,795,000	>14
81 Harper Road	St. Thomas	10,339	2,000	1.28	EL 1990	$2,100,000	>200
45205 Talbot Line	St. Thomas	7,450	n/a	1.74	C1-19 2004	$2,199,999	>140

Land Sales

MARKET AND VALUATION SUMMARY – ST. THOMAS INDUSTRIAL

25 SPARLING ROAD
ST. THOMAS, ON

>4 Acre Land Sale Comps

Property Address	City	Lot Size	Zoning	Price Per Acre	Total Purchase	Sold Date
10 Highbury Avenue	St. Thomas	5.00	EL	$500,000	$2,500,000	Active
Dennis Rd (PIN 351630323)	St. Thomas	18.17	EL	$247,661	$4,500,000	06/05//2023
1 Ontario Road	St. Thomas	4.22	EL	$132,701	$560,000	09/22/2023

Pricing Guidance

MARKET AND VALUATION SUMMARY – STRATFORD

827 ERIE STREET
STRATFORD, ON



EXECUTIVE SUMMARY

- The site is 2.98 acres with a 6,996 SF building with an I1 zoning that is permissive.
- Fair Market Value range is $1.96 to $2.26 M[1].
- JLL recommends pricing 827 Erie Street between $2.1M - $2.4 M with a view to transacting between $2.0-$2.3 M, closer to our high-end pricing below.

Split for accounting treatment

- Building to lot coverage is 5.39% and so this is more of a land play than building play, especially at $500-600k an acre.
- Land Value is therefore determined to be $0.45 to 0.525M (1.64 acres x $0.738-$0.861 per acre)
  Building Value makes up the difference at $1.22M to $1.4 M

[1] Using a price per SF of $140 – $160 based on comparable building quality sales, we value the building and underlying/adjacent land at between $0.93-1.067 M. Using a price per an acre of 1.4-1.6M per acre, we value the acres of excess land at $0.51 - $0.58 M.

PRICING GUIDANCE

MARKET AND VALUATION SUMMARY – STRATFORD INDUSTRIAL

827 ERIE STREET
STRATFORD, ON

- The valuation for 827 Erie Street requires looking at the building in two components 1) the building with reasonably associated land and 2) the excess land for the property.
- With the excess land at 827 Erie Street and using a market lot coverage of 45% suggests an excess land area of 1.64 acres. However, with no recent land sales and only one for sale opportunity at $481,000 per acre in and around Stratford, JLL has extrapolated a range of $450,000-525,000 per acre as land value as discounts from Woodstock land of $550,00 per acre.
- The combined suggested pricing of building and excess land would put the value of 827 Erie Street between $ 1.96 to $2.26 million.
- In order to achieve pricing in that price range or greater we recommend listing the property between $2.1 to $2.4 million.

Valuation	Building size	Price PSF	Building Price (incl. land under building) (a)	Excess Land Size	Price per acre	Excess Land Price (b)	Total Site Price (a) + (b)
Low End	6,996	$175	$1,224,300	1.64	$450,000	$737,550	$1,961,850
High End	6,659	$200	$1,399,200	1.64	$525,000	$860,475	$2,259,675

Building Sales

MARKET AND VALUATION SUMMARY – STRATFORD INDUSTRIAL

827 ERIE STREET
STRATFORD, ON

Sale Comps

Property Address	City	Total Area (SF)	Lot Area (Acres)	Zoning	Sold Price	Sold Firm Date
51 Griffith Road	Stratford	3,268	1.0	I2	$1,000,000	22-Sep-23
212 Bergey Court	New Hamburg	10,386	2.08	Z10	$2,995,000	13-Nov-23

Available Buildings For Sale

MARKET AND VALUATION SUMMARY – STRATFORD INDUSTRIAL

827 ERIE STREET
STRATFORD, ON

Available Properties

Property Address	City	Total Area (SF)	Office (SF)	Lot Area (Acres)	Zoning	Asking Price	Days on Market
117 Regent Street	Stratford	1,920	TBD; 2 private offices	0.214	I2	$699,000	100-200
136 James Street S	St. Marys	4,900	1,100	0.305	C3	$850,000	100-200

Land Sales

MARKET AND VALUATION SUMMARY – STRATFORD INDUSTRIAL

827 ERIE STREET
STRATFORD, ON

>4 Acre Land For Sale

Property Address	City	Lot Size (net developable)	Zoning	Price Per Acre	Total Purchase	Sold Date
3797 Downie 112 Road	Stratford	8.45 acres	I2	$481,065	$4,065,000	NA

Juteau Johnson Comba Inc
Real Estate Appraisers & Consultants

J
J
C

Appraisal Report on:
400 Coventry Road
Ottawa, Ontario

Effective Date:
August 14, 2019

Report Date:
August 19, 2019

Prepared for:
Enbridge Gas Distribution Inc.

2255 St. Laurent Blvd.
Suite 340
Ottawa, Ontario
K1G 4K3

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Juteau Johnson Comba Inc
Real Estate Appraisers & Consultants

August 19, 2019

Reference No. 164-19-15

Enbridge Gas Distribution Inc.
200, 425 - 1st Street S.W.
Calgary, Alberta
T2P 3L8

Attention: Mr. Henry Van Zalingen, CPA, CGA
Manager, Real Estate

Dear Sir

Re: Appraisal Report on 400 Coventry Road, Ottawa, Ontario

In accordance with your request, we have inspected the above-noted property for the purpose of providing you with an estimate of the current market value of the fee simple interest in the subject property under its Highest and Best Use. In this regard, the existing improvements are not considered to contribute value over and above that of the underlying land. Our value estimate is free and clear of mortgage or other encumbrances, unless otherwise indicated. The effective date of appraisal is August 14, 2019, the date a cursory inspection of the property was undertaken. The appraisal report is based on the following key assumptions:

- the subject site and neighbouring lands are free of environmental contaminants or hazardous substances;
- the subject soils are suitable for redevelopment of the site to its Highest and Best Use; and
- adequate servicing capacity, including hydro, is available to support the redevelopment of the subject site to its Highest and Best Use such that no abnormal/extraordinary costs are incurred on redevelopment.

Should any of the foregoing assumptions prove to be incorrect, an adjustment to our valuation may be warranted.

As a result of our investigations and analysis, it is our opinion that the estimated current market value of the fee simple interest in the subject property, based on its Highest and Best Use as a redevelopment site, as at August 14, 2019, is:

THIRTEEN MILLION NINE HUNDRED AND THIRTY-FIVE THOUSAND DOLLARS ($13,935,000)

. . . /2

Juteau Johnson Comba Inc
Real Estate Appraisers & Consultants

It is our understanding from the City of Ottawa (Erin O'Connell - Planner) that there is an error in the zoning by-law concerning the GM zone for the subject site which is to be corrected this Fall to allow for high-rise apartment development. Our valuation assumes this is the case.

We have prepared this report for you and your associates for the specific use referred to herein. It is not to be reproduced, in whole or in part, without the written consent of the undersigned. Neither our name nor the material submitted may be included in any prospectus, newspaper publicity or as part of any printed material, or used in offerings or representations in connection with the sale of securities or participation interests to the public, without our prior written consent. Liability is expressly denied to any person other than the client and those who obtain written consent from the client and the author of the report. Accordingly, no responsibility is accepted for any damage suffered by any such person as a result of decisions made or actions based on the report. The report is only valid if it bears the original signature of the author.

Our report providing details of the property and our method of valuation is attached. If we can be of further assistance in these or other matters, please do not hesitate to contact us.

Yours truly,

JUTEAU JOHNSON COMBA INC

Jennifer Johnson, B.Comm., AACI, P.App.

2255 St. Laurent Boulevard, Suite 340, Ottawa, Ontario, K1G 4K3
Phone: 613-738-2426 Fax: 613-738-0429

AERIAL MAP OF SUBJECT PROPERTY



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ADDENDUM

Appendix A	Photographs of Subject Property
Appendix B	Comparable Sales

SUMMARY OF SALIENT FACTS AND IMPORTANT CONCLUSIONS

TERMS OF REFERENCE

Purpose of Appraisal:	To estimate the current market value of the fee simple interest in the subject property, under its highest and best use. Our value estimate is free and clear of mortgage or other encumbrances, unless otherwise indicated.
Intended Use of Appraisal:	To assist the client in estimating the current market value of the subject property for internal decision making purposes. This report is intended for the use of the client only, namely, Enbridge Gas Distribution Inc.
Effective Date of Appraisal:	August 14, 2019
Date of Inspection:	August 14, 2019

PHYSICAL DATA

Municipal Address:	400 Coventry Road, Ottawa
Location:	Southwest corner of Coventry and Belfast Roads, and also fronting the north side of the Queensway (Highway #417), in the Coventry/Belfast Industrial Area of the City of Ottawa.
Legal Description:	Part of Lot 3 on Plan 747, as in OT67675, Except Part 1 on Plan 5R-9075, City of Ottawa. Subject to an Interest in OT42230, if any. (PIN 04255-0084)
Site Area:	4.922 acres (214,392 square feet) - as per plan provided
Existing Improvements:	Original (1966/67), single-storey service industrial building comprised of warehousing, vehicle repair facilities and the cafeteria. Single-storey addition of some 6,300 square feet constructed in 1980/81 housing the planning area (offices). Leasable area is reported at 40,062 square feet. Three-storey, elevatored, office building addition constructed in 1990/91. Leasable area is reported at 34,500 square feet.
Zoning:	GM6 H(34) - General Mixed Use Zone GM6 H(90) - General Mixed Use Zone
Highest and Best Use:	Redevelopment which maximizes the development potential of the site potentially for apartment use for which there is strong

demand in the current market or mixed use development (i.e. residential/commercial), in accordance with the requirements of the zoning by-law. The existing improvements are not considered to contribute value over and above that of the underlying land but their use may be continued in the interim.

MARKET VALUE ESTIMATE: **$13,935,0000 ($65/sf of site area, $32.50/sf of FSI/gfa)**

SCOPE OF THE APPRAISAL

The Scope of the Appraisal describes the extent of the process of collecting, confirming and reporting data. In regard to the subject property, this involved the following.

The appraisal commenced with a preliminary investigation undertaken to determine market trends, influences and other significant factors pertinent to the subject property. The property was inspected on August 14, 2019, together with the surrounding neighbourhood at which time the subject photographs were taken. A cursory inspection of the improvements was undertaken. It is of note that an inspection is not the equivalent of an inspection by others such as an architect, a professional engineer, a licensed home inspector, plumber, electrician, carpenter, heating/cooling experts or other licensed trade specialists. The scope of the inspection is a visual observation by walk through. The legal description was based on GeoWarehouse records. Site dimensions and area were taken from a Topographical Plan provided by the client and prepred by Annis, O'Sullivan, Vollebekk Ltd., dated February 15, 2013. Zoning information was extracted from the City of Ottawa's Comprehensive Zoning By-law 2008-250. Market data sources included information contained in our files, the Land Registry Office, and other appraisers, realtors or persons knowledgeable of the subject property marketplace.

This appraisal complies with our understanding of the requirements of the Canadian Uniform Standards of Professional Appraisal Practice of the Appraisal Institute of Canada. We did not complete technical investigations such as:

- detailed inspections of the structure, roof or mechanical systems;
- an environmental review of the property;
- a survey of the site;
- investigations into the bearing qualities of the soils.

The analysis contained in this report relied on written and verbal information of market transactions. Data and statistics were obtained from a variety of sources we considered reliable. A concerted effort was made to verify the accuracy of the information contained herein. If information independently researched by the appraiser or provided by the client/owner on the surface appeared to be reasonable, it was relied on as true and correct. No in-depth investigation was made into the parties to real estate transactions and audits were not performed on documents or information provided. We reserve the right to revisit the value if the information received from a third party is incorrect.

Appraisers are not qualified in professional matters like land surveying, engineering, architecture and the law, nor are they qualified as building inspectors. Investigations into matters such as these do not form part of an appraiser's investigations. We have assumed that there are no hidden or unapparent conditions of the property, sub-soil or structures that render it more or less valuable. No responsibility is assumed for such conditions or for arranging for engineering studies that may be required to discover them. Where matters were observed that appeared unusual, they have been noted in this report. The services of experts in these fields are required to investigate the possibility that defects are present.

TERMS OF REFERENCE

Purpose of Appraisal

The purpose of this appraisal is to estimate the current market value of the fee simple interest in the subject property, under its highest and best use. Our value estimate is free and clear of mortgage or other encumbrances, unless otherwise indicated. The appraisal report is based on the following key assumptions among other assumptions outlined herein:

- the subject site and neighbouring lands are free of environmental contaminants or hazardous substances;
- the subject soils are suitable for redevelopment of the site to its Highest and Best Use; and
- adequate servicing capacity, including hydro, is available to support the redevelopment of the subject site to its Highest and Best Use such that no abnormal/extraordinary costs are incurred on redevelopment.

Should any of the foregoing assumptions prove to be incorrect, an adjustment to our valuation may be warranted.

Intended Use of Appraisal

The intended use of the report is to assist the client in estimating the current market value of the subject property for internal decision making purposes.

Intended User

The intended user of the report is the client, namely, Enbridge Gas Distribution Inc.

Definition of Market Value

For the purpose of this appraisal, market value is defined as:

> *The most probable price which a property should bring in a competitive and open market as of the specified date under all conditions requisite to a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus. Implicit in this definition are the consummation of a sale as of the specified date and the passing of title from seller to buyer under conditions whereby:*
>
> 1. *buyer and seller are typically motivated;*
>
> 2. *both parties are well informed or well advised, and acting in what they consider their best interests;*

3. *a reasonable time is allowed for exposure in the open market;*

4. *payment is made in terms of cash in Canadian dollars or in terms of financial arrangements comparable thereto; and*

5. *the price represents the normal consideration for the property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.*

The foregoing definition was extracted from the Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) dated August 1, 2018.

Property Rights Under Appraisal

The interest being appraised is that of the fee simple, free and clear of mortgage and/or lien encumbrances. Fee simple is defined in "The Appraisal of Real Estate - Third Canadian Edition" as:

> *absolute ownership unencumbered by any other interest or estate, subject only to the limitations imposed by the governmental powers of taxation, expropriation, police power, and escheat.*

Definition of Exposure Time

Exposure time, as per the Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) dated August 1, 2018, may be defined as follows:

> *The estimated length of time the property interest being appraised would have been offered on the market before the hypothetical consummation of a sale at the estimated value on the effective date of the appraisal.*

Exposure time is different for various types of real estate and under various market conditions. It should be noted that the overall concept of reasonable exposure encompasses not only adequate, sufficient and reasonable time but also adequate, sufficient and reasonable effort.

Our value estimate assumes an exposure time of three to six months.

Effective Date of Appraisal

The effective date of appraisal is August 14, 2019.

Date of Inspection

A cursory inspection of the property was undertaken August 14, 2019.

IDENTIFICATION OF THE PROPERTY

Location

The subject property is located at the southwest corner of Coventry and Belfast Roads, and also fronts the north side of the Queensway (Highway #417), in the Coventry/Belfast Industrial Area of the City of Ottawa. Its municipal address is 400 Coventry Road, Ottawa.

Legal Description

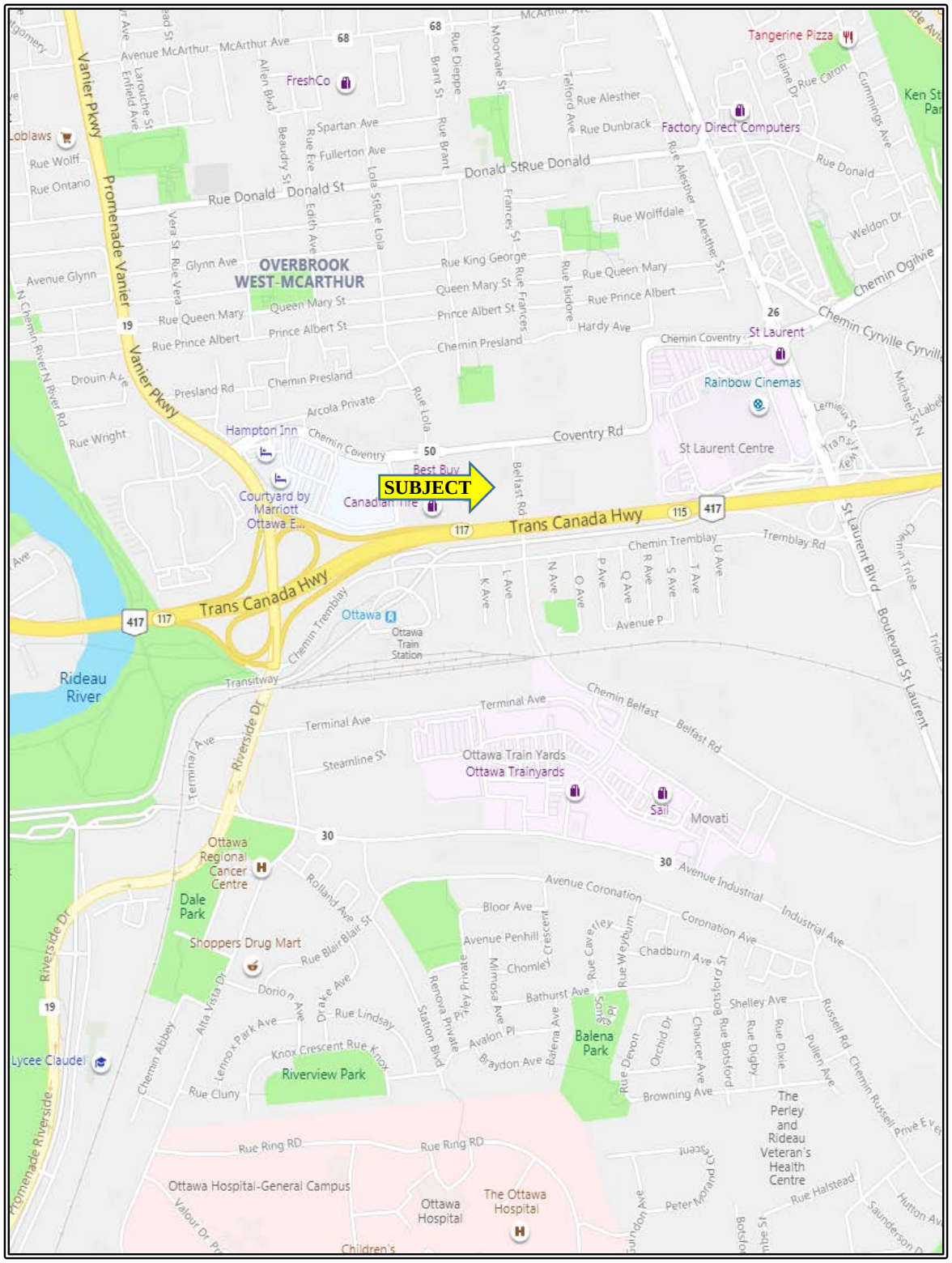
The subject property is legally described as Part of Lot 3 on Plan 747, as in OT67675, Except Part 1 on Plan 5R-9075, City of Ottawa. It is subject to an interest in OT42230, if any. The subject is identified in the Land Registry Office as PIN (property identification number) 04255-0084.

The foregoing legal description was taken from GeoWarehouse (an on-line service providing access to land registry data and updated regularly from the POLARIS data base - the automated land records management system for the Province of Ontario). It is assumed to be correct, however, it should not be relied upon as accurate without obtaining a qualified legal opinion. We have made no investigations into the title of the property. Further, any documents registered on title have not been read. This report has been prepared on the premise that the property is free and clear of all liens and encumbrances, unless otherwise indicated, and on the assumption that the improvements do not encroach on any adjoining lands. It is assumed that any existing easements registered or unregistered do not have a negative impact on the value of the subject property as estimated herein. There is reported to be a public utility easement in favour of Ontario Hydro and Bell Canada along the southern property line. Based on the Topographical Plan provided, the easement is 8 feet in width.

Ownership/Sales History

Based on a review of GeoWarehouse records, the subject property has not sold within the past three years nor have we been made aware of any listings or agreements of purchase and sale affecting the property over the past year. It is currently registered to Enbridge Gas Distribution Inc.

LOCATION MAP



NEIGHBOURHOOD DESCRIPTION

The subject property is situated at the southwest corner of Coventry and Belfast Roads and also fronts the north side of the Queensway (Highway #417), in the Coventry/Belfast Industrial Area of the City of Ottawa. The neighbourhood is bound by Coventry Road to the north, St. Laurent Boulevard to the east, Industrial Avenue to the south and Riverside Drive/Vanier Parkway to the west. The area represents the western extension of the Sheffield-Lancaster Industrial Area. It is part of an employment area focussed about Industrial, Belfast and Coventry Roads that is in transition to retail and office functions.

The neighbourhood is some four kilometres east of Ottawa's downtown core and is bisected by the Queensway, the Region's main east/west thoroughfare. Access to the Queensway is readily available to the subject site from either the Vanier Parkway to the west or St. Laurent Boulevard to the east. The transitway also bisects the neighbourhood with transit stations at the St. Laurent Shopping Centre and Ottawa Train Station. Ottawa's new Light Rail Transit Confederation line runs between Blair Road in the east and Tunney's Pasture in the west, including a single dual track underground tunnel in the downtown core. Construction on this first phase of the LRT (light rail transit) commenced in 2013 and is essentially complete and currently in the testing phase. It is expected to be operational in Q3 2019. The southwest fringe of the subject site is within 600 metres of the Tremblay LRT station located at the Ottawa VIA Rail station, to the southwest. The St. Laurent LRT station is approximately 800 metres southeast of the subject, adjacent to the St. Laurent Shopping Centre. Overall, the area is well linked to the regional road network.

Developments of note in the neighbourhood include the following:

- the federal government's 2009 purchase of 29.6 acres at the southwest corner of Tremblay Road and St. Laurent Boulevard to the east of the subject, known as 530 Tremblay Road. It is ultimately anticipated that the site will accommodate a mix of uses including residential (townhouse/apartment) and some 2.2 million square feet of office space.
- Ottawa Train Yards - a 110-acre site located on the north and south sides of Industrial Avenue, south side of Terminal Avenue, east side of Sandford Fleming Avenue and either side of Train Yards Drive. It houses over 800,000 square feet of retail space and is shadow anchored by Walmart. Major retailers include Michaels, Sail Baron, Marshalls, Movati, Farm Boy, LCBO, Nordstrom Rack, Bed Bath and Beyond, Dollarama and Golf Town. The Ottawa Train Yards is also proposed to accommodate a major office park development. Current plans call for five buildings totalling some 1.765 million square feet. An eight-storey office building of some 269,000 square feet was constructed in 2013 and is occupied by the federal government. A second nine-storey office building of some 165,000 square feet was completed in 2016 and was recently (Q4 2018) leased to the federal government. In addition, there is now a proposal for seven apartment buildings totalling 1,881 units along the south side of Steamline Street.
- St. Laurent Shopping Centre, a regional mall, situated at the northwest quadrant of St. Laurent Boulevard and the Queensway. The Sears space remains vacant. The mall is some 500 metres east of the subject property.
- Best Buy and Canadian Tire stores to the immediate west of the subject.

- Ottawa Train Station situated on the south side of Tremblay Road east of Riverside Drive.
- Ottawa's main postal terminal located at the northwest corner of Industrial and Sandford Fleming Avenues.
- OC Transpo terminal located at the northwest corner of Belfast Road and St. Laurent Boulevard.
- RCGT Stadium - Ottawa's baseball stadium located on the south side of Coventry Road, east of the Vanier Parkway.
- Ottawa Conference and Event Centre (former Hampton Conference Centre) located to the west of the baseball stadium, at Coventry Road and the Vanier Parkway and offering two on-site hotels totalling 576 rooms and 43,000 square feet of meeting room space.
- Dymon is proposing a 5-storey, 178,000 square foot self storage facility at 851 Industrial Avenue.

Coventry Road, along which the subject fronts, is home to a mix of uses including the baseball stadium, conference centre, Dymon self storage facility, office buildings, retail and older single-storey quasi retail/industrial buildings. Belfast Road is more industrial in nature.

A small residential pocket, known as Eastway Gardens, is situated within the neighbourhood on several cul-de-sacs extending off Tremblay Road (Avenues K to U). The housing stock in this area consists principally of older bungalows, duplexes and triplexes with newer townhouses having been built next to the CNR line to the south of Tremblay Road.

In conclusion, the subject property is centrally located, some four kilometres east of Ottawa's Core, within the established Coventry/Belfast Industrial Area of the City of Ottawa. It is readily accessible via a number of arterial roads, is near public transit, and benefits from excellent access via and expossure to the Queensway (Highway #417). Given the locational attributes of the neighbourhood, it is being transformed from an industrial area to an employment centre with continued intensification expected in support of the LRT.

TOPOGRAPHICAL PLAN OF

PART OF LOT 3
REGISTERED PLAN 747
CITY OF OTTAWA

Prepared by Annis, O'Sullivan, Vollebekk Ltd.

Scale 1 : 300

12 9 6 3 0 6 12 Metres

Metric

DISTANCES SHOWN ON THIS PLAN ARE IN METRES AND CAN BE CONVERTED TO FEET BY DIVIDING BY 0.3048

FEB. 15 2013
Date

E.H. Herweyer O.L.S.

BELFAST ROAD

PIN 04254 - 0076

PLAN 5R-9075 (PLAN P-3409-74)
PIN 04255-0001

OVERPASS

COVENTRY ROAD

PIN 04254 - 0077

Approximate Centreline of Construction

GLOUCESTER (QUEENSWAY) HIGHWAY 417

PIN 04255 - 0001 (MTO PLAN 5R-5421)

PART 2 PLAN 4R-23509

PART 1 PLAN 4R-23509

PIN 04255 - 0242 PART 17 PLAN 4R - 17062

LOT 3 PLAN 747

SUBJECT TO EASEMENT INST. OT42230

EASEMENT INST. OT42230

JOB BENCHMARK
TOP OF SPINDLE
Elev.=65.67

3 STOREY
BRICK & METAL SIDED BUILDING
(Brick Noted)

No. 400
COVENTRY ROAD
1 STOREY
BRICK BUILDING
(Brick Noted)

No. 380
"BEST BUY"
(Precast Noted)

No. 380
"STARBUCKS"

Gas Storage Area

Concrete Pad with Fuel Pumps

Concrete Walls

Storage Bays

Bearings are grid.

SITE AREA = 19917 m²

BOUNDARY INFORMATION COMPILED FROM PLANS 4R-23509, 5R-9075, 5R-5421 AND (AOG) SURVEY DATED FEBRUARY 6, 1990.

Notes & Legend

Denotes		
○ MH-T	-	Maintenance Hole (Traffic)
○ MH-H	-	Maintenance Hole (Hydro)
○ MH-ST	-	Maintenance Hole (Storm Sewer)
○ MH-B	-	Maintenance Hole (Bell Telephone)
□ CB	-	Catch Basin
□ DI	-	Ditch Inlet
CPP	-	Plastic Drain Pipe
□ HH	-	Handhole
T/P	-	Top of Pipe
○ B	-	Bollard
△ S	-	Sign
CLF	-	Chain Link Fence
MF	-	Metal Fence (Wrought Iron)
CRW	-	Concrete Retaining Wall
○ PO-W	-	Wood Pole
○ PO-C	-	Concrete Pole
○ AN	-	Anchor
	-	Deciduous Tree
	-	Coniferous Tree
FH	-	Fire Hydrant
WV	-	Water Valve
GFP	-	Fuel Pump on Concrete Base
Ø	-	Diameter
+ 65.00	-	Location of Elevations
+ 65.00*	-	Location of Elevations (Top of Wall)
+ 65.00^	-	Location of Elevations (Top of Curb)
T/G	-	Top of Grate
C/L	-	Centreline
Inv.	-	Invert
	-	Property Line
○ LS	-	Light Standard
⊕ FP	-	Flag Pole
—□—	-	Survey Monument Planted
—■—	-	Survey Monument Found
SIB	-	Standard Iron Bar
SSIB	-	Short Standard Iron Bar
"	-	Survey Monument 0.3 Long
(WIT)	-	Witness
(AOG)	-	Annis, O'Sullivan, Vollebekk Ltd.
OHW	-	Overhead Wires

ELEVATION NOTES

1. Elevations shown are referred to geodetic datum.
2. It is the responsibility of the user of this information to verify that the job benchmark has not been altered or disturbed and that it's relative elevation and description agrees with the information shown on this drawing.

UTILITY NOTES

1. This drawing cannot be accepted as acknowledging all of the utilities and it will be the responsibility of the user to contact the respective utility authorities for confirmation.
2. Only visible surface utilities were located.
3. A field location of underground plant by the pertinent utility authority is mandatory before any work involving breaking ground, probing, excavating etc.

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Ontario Land Surveyors

Job No. 13423-(2 Edredge PNL1 X PL T IF

REGISTERED

X:\2013\JAN\13JPINAU\13423-(2 Edredge PNL1 XR-1.dwg, 15/02/2013 8:45:05 AM, EP 7700 Bond.pc3

SITE DATA

Location:	Southwest corner of Coventry and Belfast Roads, and also fronting the north side of the Queensway (Highway #417), in the Coventry/Belfast Industrial Area of the City of Ottawa.
Municipal Address:	400 Coventry Road, Ottawa
Configuration:	Approximately rectangular
Approximate Dimensions:	- 342 feet of frontage along the south side of Coventry Road; - 611 feet of frontage along the west side Belfast Road; - 324 feet of frontage along the north side of the Queensway (Highway #417); and - westerly boundary measures 620 feet.
Site Area:	4.922 acres (214,392 square feet) - as per plan opposite
Topography:	Site is more or less level. It is below the grade of Belfast Road which slopes upward in a southern direction to provide access over the Queensway.
Access:	Vehicular access is available from both Coventry and Belfast Roads. Belfast/Coventry is a signalized intersection. The main entrance is currently from Coventry Road.
Services:	Full municipal services are available to the subject site, including water, hydro, telephone, gas and sewers. Our valuation assumes that adequate servicing is available to support the redevelopment of the subject site to its Highest and Best Use such that no abnormal/extraordinary costs are incurred on redevelopment.
Environmental Concerns:	An environmental audit has not been conducted in conjunction with the preparation of this report. It is assumed that hazardous substances do not exist. It should be clearly understood that we are not qualified to detect, test for, investigate, or otherwise ascertain the existence of such substances. As such, we do not assume any responsibility for their existence or any costs associated with their removal, correction, or treatment, in the event that they are found to exist on the subject property, or on adjacent lands. Further, it is assumed that soils are suitable to support redevelopment of the site to its Highest and Best Use. It is of note that a vehicle repair facility operates on site. It is assumed that contamination is not present as a result of this use.

If property is found to be impacted by contamination or the soils deficient in load bearing capabilities, a change to our value conclusion would be warranted.

Existing Improvements:

Original (reported 1966/67), single-storey service industrial building comprised of warehousing, vehicle repair facilities and the cafeteria. The warehousing/vehicle repair area is served by six overhead doors one of which is provided with a dock leveller. A single-storey addition of some 6,300 square feet was reported to have been constructed in 1980/81 housing the planning area (offices). Leasable area is reported at 40,062 square feet. There is a small basement area housing the gas fired boiler.

Three-storey, elevatored, office building addition constructed in 1990/91 (reported). Leasable area is reported at 34,500 square feet. Office finish generally comprises carpet or carpet tile flooring, acoustic tile ceiling, vinyl covered demountable partitioning and painted perimeter drywall. Washroom finish is generally original being ceramic tile floor and wall finish with acoustic tile ceilings. Ground and second floor corridors are vinyl tile. Heating/cooling is provided by a number of rooftop HVAC units. Supplemental perimeter heating is also supplied by a gas fired boiler.

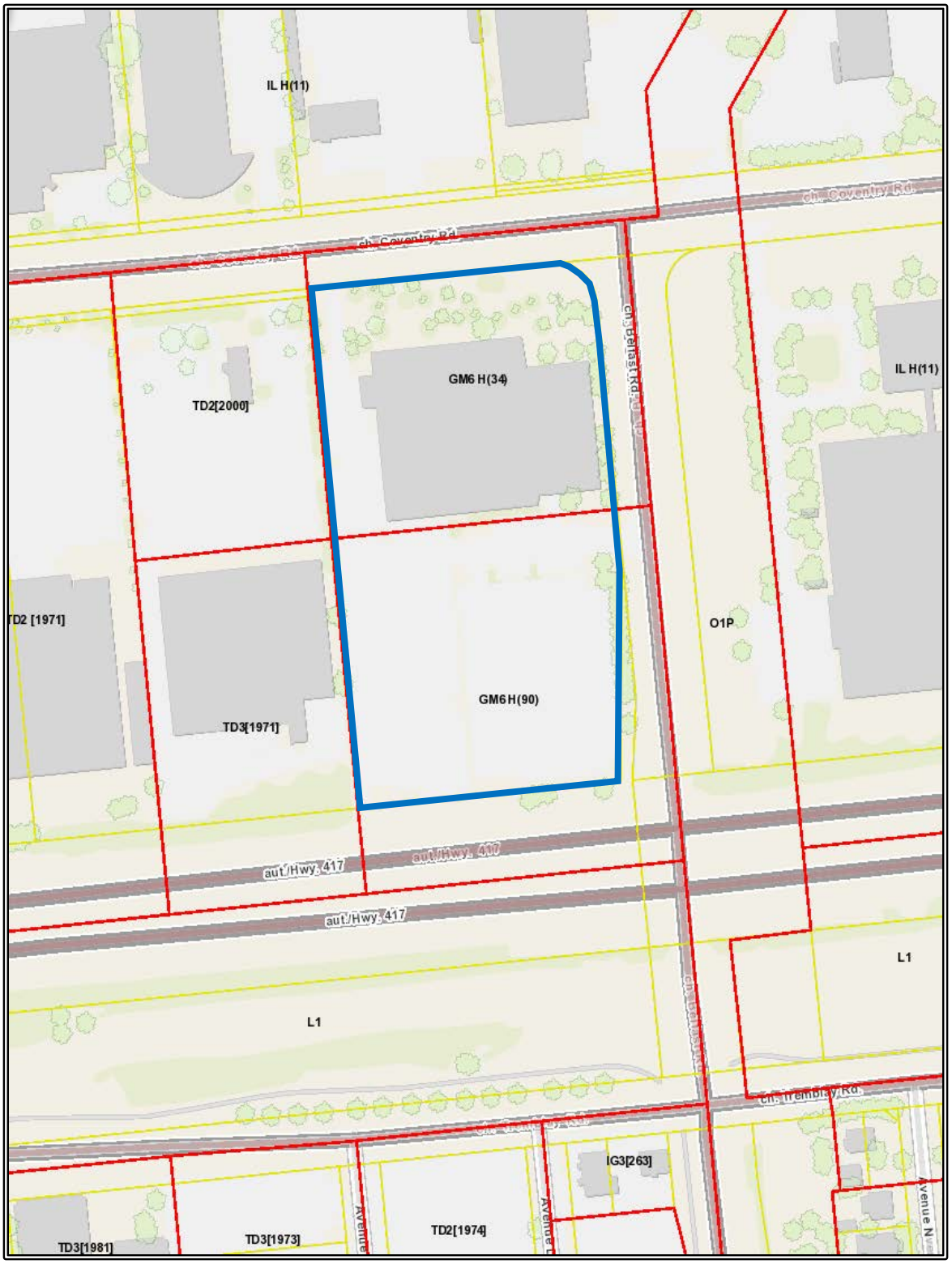
Leasable areas were confirmed as reasonable with MPAC (Municipal Property Assessment Corporation) report.

The improvements are situated on the northern part of the site while the southern part is paved accommodating parking and providing truck access to the grade level loading doors. The Coventry and Belfast Road frontages are landscaped.

Overall, the subject is considered to be in average condition.

Photographs of the subject property are presented in Appendix A.

ZONING MAP


IL H(11)
ch. Coventry Rd.
GM6 H(34)
TD2[2000]
IL H(11)
TD2 [1971]
O1P
GM6 H(90)
TD3[1971]
aut./Hwy. 417
aut./Hwy. 417
aut./Hwy. 417
L1
L1
ch. Trembley Rd.
IG3[263]
TD3[1981]
TD3[1973]
TD2[1974]
Avenue N

LAND USE REGULATIONS

CITY OF OTTAWA OFFICIAL PLAN

The subject property is designated Mixed-Use Centre under the City of Ottawa Official Plan. Mixed Use Centres occupy strategic locations on the Rapid-Transit network and act as central nodes of activity within their surrounding communities and the city as a whole. These centres are a critical element in the City's growth management strategy, being areas with potential to achieve high densities and compact and mixed-use development oriented to rapid transit. More jobs and housing at these locations will increase transit ridership and draw more commuter travel to these locations. In the long term the centres will become complete, liveable communities that attract people for the jobs, leisure, lifestyle and business opportunities they provide [OP Amendment #150, October 19, 2018].

Mixed Use Centres are to become more transit-supportive destinations through intensification and development of vacant land.

ZONING

In accordance with the City of Ottawa Zoning By-law 2008-250, the subject property is designated as follows:

Northern approximately 104,623 square feet - GM6 H(34) - General Mixed Use Zone
Southern approximately 109,769 square feet - GM6 H(90) - General Mixed Use Zone

The foregoing areas were estimated based on the GeoOttawa web site using the Advanced Draw and Measures tool and are assumed to be reasonable.

The purpose of the General Mixed Use Zone is to:

(1) allow residential, commercial and institutional uses, or mixed use development in the General Urban Area and in the Upper Town, Lowertown and Sandy Hill West Character Areas of the Central Area designations of the Official Plan;

(2) limit commercial uses to individual occupancies or in groupings in well defined areas such that they do not affect the development of the designated Traditional and Arterial Mainstreets as viable mixed-use areas;

(3) permit uses that are often large and serve or draw from broader areas than the surrounding community and which may generate traffic, noise, or other impacts provided the anticipated impacts are adequately mitigated or otherwise addressed; and

(4) impose development standards that will ensure that the uses are compatible and complement surrounding land uses.

The GM zone permits a wide variety of residential and non-residential uses including, among others:

- apartment dwelling, low rise;
- apartment dwelling, mid rise*;
- dwelling unit;
- planned unit development;
- retirement home;
- bank;
- convenience store;
- instructional facility;
- medical facility;
- office;
- restaurant;
- retail food store;
- retail store;
- service and repair shop;
- technology industry; and
- training centre.

* An apartment dwelling mid-rise means a residential use building that is more than four storeys but less than ten storeys in height and contains four or more principal dwelling units, other than a townhouse dwelling or stacked dwelling.

It is our understanding from the City of Ottawa (Erin O'Connell - Planner) that there is an error in the zoning by-law concerning the GM zone for the subject site which is to be corrected this Fall to allow for high-rise apartment development. Our valuation assumes this is the case.

Zone provisions include the following:

Minimum Lot Area:	No minimum
Minimum Lot Width:	No minimum
Minimum Front Yard & Corner Side Yard Setbacks:	9.8 feet
Maximum Building Height:	
Northern Portion of Site:	111.5 feet (+/-10 storeys)
Southern Portion of Site:	295.3 feet (+/-30 storeys)
Maximum Floor Space Index:	2.0, unless otherwise indicated

With respect to the subject property, the current zoning allows a gross floor area, as defined under the zoning by-law, equivalent to two times site area or 428,784 square feet (214,392 sf x 2.0).

The existing office use represents a permitted use under the zoning by-law and is assumed to represent a legal use. The industrial use appears to represent a legal non-conforming use. A compliance report from the City would be required to verify that this is the case, which is beyond the scope of this assignment. The current use is assumed to be legal.

HIGHEST AND BEST USE

Highest and Best Use may be defined as "*that use from among reasonably probable and legal alternative uses, found to be physically possible, appropriately supported, financially feasible and which results in the highest land value".*

The subject site is located at the southwest corner of Coventry and Belfast Roads, and also fronts the north side of the Queensway (Highway #417), in the Coventry/Belfast Industrial Area of the City of Ottawa. It is improved with an older/original, single-storey, industrial building providing for warehousing, vehicle repair facilities and a cafeteria plus a one-storey addition housing the planning area (1980/81) and a more recent (1991) three-storey office building. The overall development is reported to comprise a leasable area of some 74,562 square feet. The existing improvements represent a significant under utilization of the site with some 40,062 square feet of single-storey premises of which approximately 45% of the project (i.e. 33,762 square feet) dates from the 1960's. The existing zoning allows for a floor space index of 2.0 which equates to a total permitted development of some 428,784 square feet of gross floor area, as defined under the zoning by-law. In our opinion, the existing improvements do not contribute value over and above that of the underlying land value.

The subject property is designated Mixed-Use Centre under the City of Ottawa Official Plan. Mixed Use Centres occupy strategic locations on the Rapid-Transit network and act as central nodes of activity within their surrounding communities and the city as a whole. In this regard, the southwestern fringe of the subject site is within 600 metres of the Tremblay LRT (light rail transit) station located at the Ottawa VIA Rail station, to the southwest. The St. Laurent station is approximately 800 metres southeast of the subject, adjacent to the St. Laurent Shopping Centre. The LRT is essentially complete and is expected to be operational in the near future. It is currently in the testing phase. It is the City's intention that, in conjunction with the LRT, Mixed Use Centres will become more transit-supportive destinations through intensification and development of vacant land (i.e. properties such as the subject).

The subject is considered well suited to redevelopment. It is a more or less rectangular, 4.922 acre parcel of land with frontage on three arterials including the Queensway, the City's primary east/west limited access highway. It is centrally located some four kilometres east of Ottawa's Core and is within the Tremblay Transit-Oriented Development (TOD) Area which has been targeted for higher density development. In this regard, it has been zoned for heights of approximately 10 storeys on the northern portion of the site and 30 storeys on the southern portion and as previously indicated is zoned to accommodate 428,784 square feet of gross floor area, as defined under the zoning by-law. It is assumed that servicing capacity and soil bearing qualities are adequate to support redevelopment of the site to its highest and best use such that no extraordinary costs are incurred.

The subject's zoning allows for a variety of both residential and commercial uses including apartment, office and retail development. There has been strong demand in the current market for apartment and in some cases mixed use sites. A recent example includes the redevelopment of single-storey retail space of some 77,000 square feet (part of the larger Silver City retail centre and adjacent to the Gloucester Centre) backing onto the Queensway east of the subject and adjacent to the Blair LRT station

which was demolished and recently redeveloped with a 23-storey, 228-unit rental apartment building known as Frontier Phase 1.

A number of developers are undertaking and looking to undertake rental apartment projects. Vacancy is tight being reported at 1.6% for 2018 (as per CMHC). Demand for purpose built apartments can be attributed to historically high levels of positive net international migration, improving employment conditions for younger households, the on-going aging of the population, the high cost of home ownership and an increasing number of people choosing to rent as a lifestyle preference. Further, much of Ottawa's rental stock is dated with 80% reported to have been constructed before 1990.

Given the subject's locational attributes within the Tremblay TOD Area which is targeted for intensification, its proximity to transit and the Core, ready accessibility and exposure to the Queensway and proximity to the St. Laurent Shopping Centre, Train Yards Power Centre and office development, its Highest and Best Use is considered to be redevelopment which maximizes the development potential of the site potentially for apartment use for which there is strong demand in the current market or mixed use development (i.e. residential/commercial), in accordance with the requirements of the zoning by-law. The existing improvements are not considered to contribute value over and above that of the underlying land but their use may be continued in the interim. It further of note that it is not uncommon for zoning variances to be sought in conjunction with the redevelopment of a site (typically related to height, setbacks, density etc.), but this is at the risk of the buyer.

VALUATION

The Direct Comparison Approach has been employed to estimate the current market value of the subject property. The Direct Comparison Approach is a valuation method whereby the property being appraised is compared to similar properties that have recently been sold or offered for sale, the assumption being if the subject property had been exposed to the market it would have been in competition with the comparable property and dealing with the same type of purchaser who would have been in the same market. The sale prices of these parcels are then adjusted for any differences and applied in the valuation of the site under appraisal.

In order to estimate the current market value of the subject property under its Highest and Best Use consideration has been given to the comparable land sales summarized as follows and presented in greater detail in Appendix B.

Sale No.	Location	Date of Sale	Site Area	Zoning (Proposed Gross Floor Area)	Sale Price	Price/sf (psf of gfa)
1	2 Robinson Avenue, Ottawa	Mar/19	246,550 sf (5.66 acres)	^_TD1[2078] ^_TD2[2078] _ ^_I1A (896,910)	$26,500,000	$107.48 ($29.55)
2	2851 & 2865 Dumaurier Avenue, Nepean	May/19	41,626 sf	GM[62] F(.25) (unknown)	$2,600,000	$62.46
3	112 Montreal Road & 314 Gardner Street, Vanier	Aug/19	124,146 sf (2.85 acre)	TM[2363]F(3.5) S365-h (unknown)	$8,500,000	$68.47 ($19.56)
4	Carling, Woodroffe and Ancaster Avenues, Ottawa	Mar/18	62,420 sf	AM10 (211,149)	$5,950,000	$95.32 ($28.18)
Subject	**400 Coventry Road, Ottawa**		**214,392 (4.922 acres)**			

Sales Analysis

The foregoing sales were analysed on the basis of price per square foot of site area and indicate a range of rates between $62.46 and $107.48.

Comparable Sale #1, 2 Robinson Avenue, represents a recent sale located east of the subject at the Queensway and Lees Avenue. Its location is judged superior being more central and proximate to Ottawa University and the Lees Avenue LRT station for which a downward adjustment to the indicated price per square foot is considered warranted. Like the subject, it is a sizeable parcel of land. The proposed density of development, which translates to an FSI of approximately 3.6, is significantly higher than can currently be accommodated on the subject site for which a sizeable downward adjustment has been applied. Less than offsetting upward adjustment have been recognized to account for the fact that this sale transacted under power of sale conditions, the site is reported to be contaminated and the clean up costs unknown, thereby presenting a significant element of risk to the buyer who purchased the site unconditionally.

Comparable Sale #2, 2851 & 2865 Dumaurier Avenue, is also a recent sale. It is located in Ottawa's west end just north of the Queensway and was purchased for future high density development, given its proximity to the future Pinecrest LRT station. In this regard, a rezoning will be required for which an upward adjustment has been applied. A further upward adjustment for location is warranted as the site is less central and the surrounding community is considered less desirable, given the significant Ottawa Community Housing component. An offsetting downward adjustment for size has been recognized. All else being equal, there tends to be in inverse relationship between size and attainable per square foot rates.

Comparable #3, 112 Montreal Road and 314 Gardiner Street, represents out most recent sale. It is located approximately 2 kilometres northwest of the subject in the Vanier community. Relative to the subject, the Vanier neighbourhood is generally judged to be less desirable and further is not on the LRT for which an upward adjustment has been applied. Further, the site's configuration is irregular which is considered an inferior feature. It benefits from a superior FSI (i.e. 3.5) for which a downward adjustment has been recognized. Notwithstanding, the purchaser is not anticipating utilizing the full FSI.

Comparable #4, Carling, Woodroffe and Ancaster Avenues, represents our oldest sale and is considered to warrant an upward adjustment for time with strong demand placing upward pressure on land values for apartment building sites. It is located in Ottawa's central west end, opposite the Carlingwood Shopping Centre, in an established residential community and is just outside the 600 metre buffer zone for the future New Orchard LRT station projected to be completed in 2025. A sizeable downward adjustment has been applied given the greater density of development proposed for the site (i.e. an FSI of some 3.4 is proposed versus the subject's zoning at 2.00). It is of note that a rezoning is required to permit the maximum height proposed of 128 feet versus that permitted of 98 feet. Overall, the subject is judged to warrant a lower per square rate, given the significantly larger size of the site and lower density permitted.

In conjunction with the foregoing, consideration has been given to the following:

- 1101 Baxter Road, the Ottawa Citizen building, was acquired in December 2018 as a longer term hold for future redevelopment being situated along the Queensway corridor. It will be readily accessible by the future Queensview LRT station via a pedestrian bridge. It is improved with an older 186,000 square foot office and newspaper production facility on a 7.71 acre parcel of land and was partially leased back to Postmedia. Like the subject, is it s unique property. The sale price was $21,000,000 which equates to $113 per square foot of building area or $62.53 per square foot of **site area.**

- a central east end site, relatively proximate to the subject, is reported to be tied up for apartment development (2 high rise) towers, at a price of $62 per square foot of **gross floor area**. This is well above that demonstrated by the sales, where available and relates to its recency and the fact that all plans and approvals are in place. The subject would warrant a rate well below this on a price per square foot of gfa basis.

In summary, the comparable sales demonstrate a range of rates between $62.46 and $107.48 per square foot of site area. The subject is judged to warrant a rate towards the lower end of the range, given its larger size. In conclusion, a per square foot rate of $65.00 per square foot of site area is considered reasonable and has been recognized. On this basis, the current market value of the subject property is estimated at:

214,392 square feet x $65.00 per square foot = $13,935,480

Rounded to:

THIRTEEN MILLION NINE HUNDRED AND THIRTY-FIVE THOUSAND DOLLARS (13,935,000)

The foregoing value estimate translates to $32.50 per square foot of FSI or permitted gross floor area (i.e. $13,935,480/428,784 sf) which is judged consistent with the comparable sales. It is above that of Sale #1 at $29.55 per square foot of gfa which represents a more central but contaminated site and Sale #4 at $28.18 per square foot of gfa to which an upward time adjustment was applied. The price per square foot of FSI for Comparable #3 is considered to be relatively low at only $19.56 per square foot. This is considered to relate to its Vanier location and sizeable FSI at 3.5 which may not be practical to achieve. Finally, the recent conditional offer we are aware of is well above this at $62.00 per square foot of gfa but includes all plans and approvals, and represents an offer only at this stage.

It is our understanding from the City of Ottawa (Erin O'Connell - Planner) that there is an error in the zoning by-law concerning the GM zone for the subject site which is to be corrected this Fall to allow for high-rise apartment development. Our valuation assumes this is the case.

ASSUMPTIONS AND LIMITING CONDITIONS

The legal description of the subject property is assumed to be correct.

In order to arrive at a supportable opinion of value, it was found necessary to utilize both documented and hearsay evidence of the marketplace. A concerted effort has been made to verify the accuracy of the information contained herein. Accordingly, the information is believed to be reliable and correct, and has been gathered according to procedures which are recognized by the Appraisal Institute of Canada.

We assume no responsibility for matters legal in character, nor do we render any opinion as to the title which is assumed to be good.

Sketches, drawings, diagrams, photographs, etc. presented in this report are included for the sole purpose of illustration. No legal survey or soil test concerning the subject property has been provided. Accordingly, no responsibility is assumed concerning these matters or other technical or engineering techniques which would be required to discover any inherent or hidden condition of the subject property.

The property rights appraised exclude mineral rights, if any. In the case of improved properties, it is assumed that the improvements conform to provincial and municipal code requirements for fire and safety regulations.

We are not aware of the content of any environmental reports, studies, or other investigations or soil surveys which may have been carried out on the property and which may have indicated the existence or possibility of contamination. In undertaking this assignment, we have been instructed to assume that no actual or potential contaminative uses have ever been carried out on the property. Further, we have not carried out any investigation into the past or present uses of either the subject property or of any adjacent properties to establish whether there is any potential for contamination from any uses on any sites adjacent to the subject and therefor assume that none exists. Should it be subsequently established that contamination exists either on the subject property or is affected from contamination on any adjacent property, this might alter or reduce this estimate or opinion of value.

It is assumed that the real estate complies in all material respects with all restrictive covenants affecting the site and has been/will be built, in all material respects, in compliance with all requirements of law, including all zoning, land classification, building, planning, fire and health by-laws, rules, regulations, orders and codes of all federal, provincial, regional and municipal governmental authorities having jurisdiction with respect thereto.

It is assumed that there are no work orders or other notices of violation of law outstanding with respect to the real estate and that there is no requirement of law preventing occupancy of the real estate as described in this report. It is further assumed that the property is free and clear of any liens or restrictive title covenants, unless specifically stated in the body.

The agreed upon compensation for services rendered in preparing this report does not include a fee for court preparation or court appearance. Should a court appearance be required in connection with this report, additional fees will have to be agreed upon.

ENBRIDGE GAS DISTRIBUTION INC. may use it in deliberations affecting the subject property only, and in so doing, the report should not be extracted, but used in its entirety.

This report is valid only to **ENBRIDGE GAS DISTRIBUTION INC.** and all liability to any other party or parties is specifically excluded.

It is assumed there are no charges against the subject property which have a bearing on the market value, except for those, if any noted in the report and/or addenda.

This report has been prepared for the exclusive use of **ENBRIDGE GAS DISTRIBUTION INC.** Possession of this report, or a copy thereof, does not carry with it the right to reproduction or publication, in whole or in part, nor may it be used for any purpose by any other than the recipient, without the written consent and approval of this firm.

Neither all nor any part of the contents of this report shall be disseminated or otherwise conveyed to the public through advertising media, public relations media, news media, sales media or other public means of communication without the prior written consent and approval of this firm.

This report or any part thereof shall not be quoted or referred to in any report or financial statement of the recipient or in any documents filed with any governmental agency without the prior written consent and approval of this firm as to the purpose, form and content of such reference.

It is assumed that there are no extraordinary/abnormal costs with redeveloping the subject site to its Highest and Best Use such as servicing or hydro costs. Further, soils are assumed to be suitable to support development of the subject to its Highest and Best Use, again, assuming no extraordinary costs are incurred.

The value conclusion is in Canadian dollars.

We do not investigate if the prospective loan and/or applicant satisfy prudent underwriting criteria. We assume no responsibility for loans made where the borrower lacks the motivation to repay the loan, or where the lender has not followed prudent lending practices.

It is our understanding from the City of Ottawa (Erin O'Connell - Planner) that there is an error in the zoning by-law concerning the GM zone for the subject site which is to be corrected this Fall to allow for high-rise apartment development. Our valuation assumes this is the case.

This report is only valid if it bears the original signature of the author.

CERTIFICATION

Re: 400 Coventry Road, Ottawa, Ontario

I certify to the best of my knowledge and belief that:

- The statements of fact contained in this report are true and correct.
- The reported analyses, opinions, and conclusions are limited only by the reported assumptions and limiting conditions, and are my personal, impartial, and unbiased professional analyses, opinions, and conclusions.
- I have no present or prospective interest in the subject matter, the property that is the subject of this report, and no personal interest with respect to the parties involved.
- I am not in a conflict of interest to undertake this assignment.
- I have no bias with respect to the subject matter, the property that is the subject of this report or to the parties involved with this assignment.
- My engagement in and compensation for this assignment were not contingent upon developing or reporting predetermined results, the amount of the value estimate, or a conclusion favouring the client.
- My analyses, opinions, and conclusions were developed, and this report has been prepared, in conformity with the Canadian Uniform Standards of Professional Appraisal Practice.
- I have the knowledge, skills and experience to complete the assignment competently.
- No one provided professional assistance or third party professional assistance to the person(s) signing this report.
- As of the date of this report, the undersigned has fulfilled the requirements of The Appraisal Institute of Canada Continuing Professional Development Program for Members.
- The undersigned is a Member in good standing of the Appraisal Institute of Canada.
- I did personally undertake a cursory inspection of the subject property on August 14, 2019.
- Based upon the data, analyses and conclusions contained herein, the current market value of the fee simple interest in the subject property based on its Highest and Best Use as a redevelopment site, as at August 14, 2019, is **$13,935,000**. The value is based on the following key assumptions (among others outlined within the report):

  - the subject site and neighbouring lands are free of environmental contaminants or hazardous substances;
  - the subject soils are suitable for redevelopment of the site to its Highest and Best Use; and
  - adequate servicing capacity, including hydro, is available to support the redevelopment of the subject site to its Highest and Best Use such that no abnormal/extraordinary costs are incurred on redevelopment.

Further it is our understanding from the City of Ottawa (Erin O'Connell - Planner) that there is an error in the zoning by-law concerning the GM zone for the subject site which is to be corrected this Fall to allow for high-rise apartment development. Our valuation assumes this is the case.

Dated: August 19, 2019

JUTEAU JOHNSON COMBA INC

Jennifer Johnson, B.Comm., AACI, P.App.

APPENDIX A

PHOTOGRAPHS OF SUBJECT PROPERTY

PHOTOGRAPHS OF SUBJECT PROPERTY
EXTERIOR ELEVATIONS





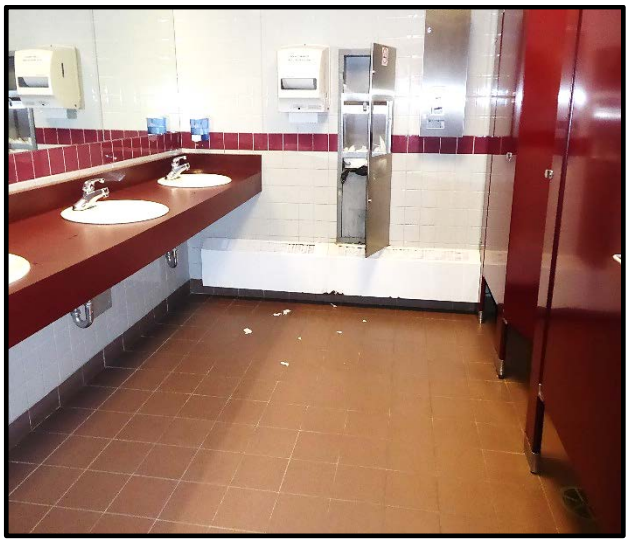




INTERIOR PHOTOS







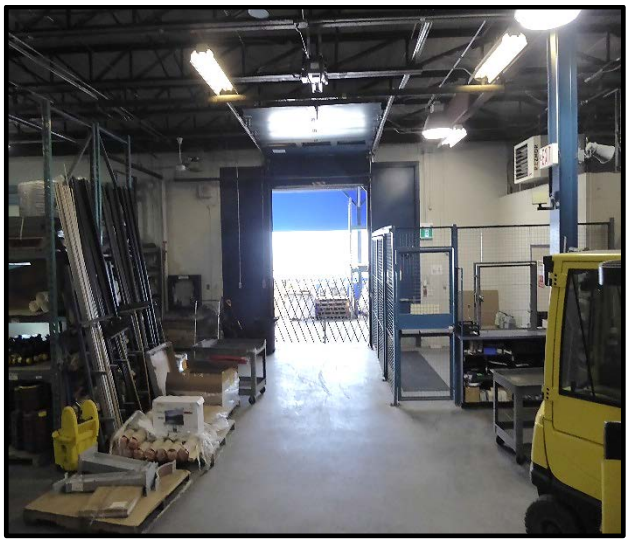




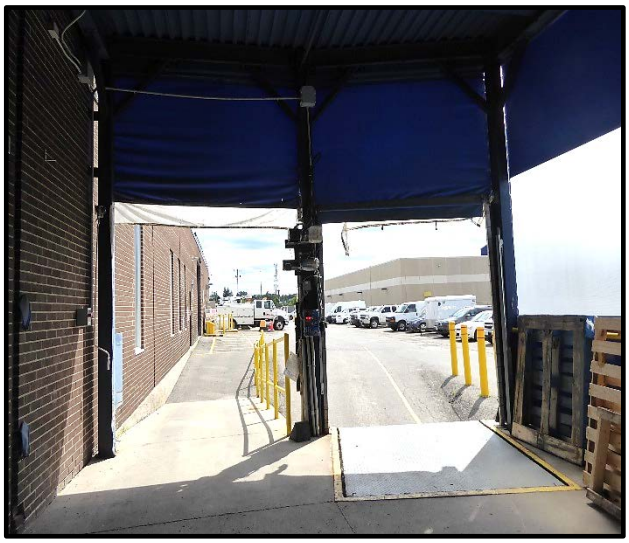









EYEWASH





APPENDIX B

COMPARABLE SALES

Comparable Sale #1



2 ROBINSON AVENUE, OTTAWA

Vendor:	Albert Gelman Inc.
Purchaser:	11182765 Canada Inc. (*Ron Lavy*)
Registration Date:	March 26, 2019
Consideration:	$26,500,000
PINs:	04204-0270, 04204-0267, 04204-0243& 04204-0245
Legal Description:	Part of Lot F, Concession D, Rideau Front, City of Ottawa
Zoning:	^_TD1[2078] - Transit Oriented Development Zone ^_TD2[2078] - Transit Oriented Development Zone ^_I1A - Minor Institutional Zone
Site Area:	5.66 acres (as per GeoWarehouse)
Price Per Square Foot:	$107.48
Proposed GFA:	896,910 square feet
Price PSF Proposed GFA:	$29.55

Remarks

The property is located on the northeast side of Lees Avenue, and the west side of Chapel Crescent, to the south of Mann Avenue, in the Sandy Hill neighbourhood, in the City of Ottawa. It is currently improved with a former Iranian Cultural Centre that has been vacant since 2012. The site will be developed with a number of buildings that will have a maximum height limit of 20 stories in the western portion of the site and 6 stories in the eastern portion of the site. It is located approximately 200 metres from the Lees LRT station and approximately 650 metres from the UOttawa LRT station. It sold pursuant to a power of sale and the site is contaminated. The clean-up cost is unknown. The purchaser’s offer was unconditional.

Comparable Sale #2



2851 & 2865 DUMAURIER AVENUE, NEPEAN

Vendor:	Giant Tiger Stores Ltd.
Purchaser:	2692539 Ontario Inc. (*Manor Park Estates Inc.*)
Registration Date:	May 22, 2019
Consideration:	$2,600,000
PIN:	03944-0826 & 03944-0238
Legal Description:	Part of Lot 20, Concession 2, Ottawa Front, City of Ottawa
Zoning:	GM [62] F(0.25) – General Mixed-Use Zone
Site Area:	41,626 square feet (as per DeedPlotter)
Price per Square Foot:	$62.46

Remarks

The property is located on the northwest corner of Dumaurier Avenue and Ramsey Crescent, in the Whitehaven-Queensway Terrace North neighbourhood, in the west end of the Ottawa. It is improved with a one-storey, steel frame, retail store of 11,256 square feet that was originally constructed in 1978. It is located within 600 metres of the Pinecrest transit station and future LRT station being part of the Phase 2 Confederation Line Extension West set to open in 2025. The property was purchased for future residential development.

Comparable Sale #3



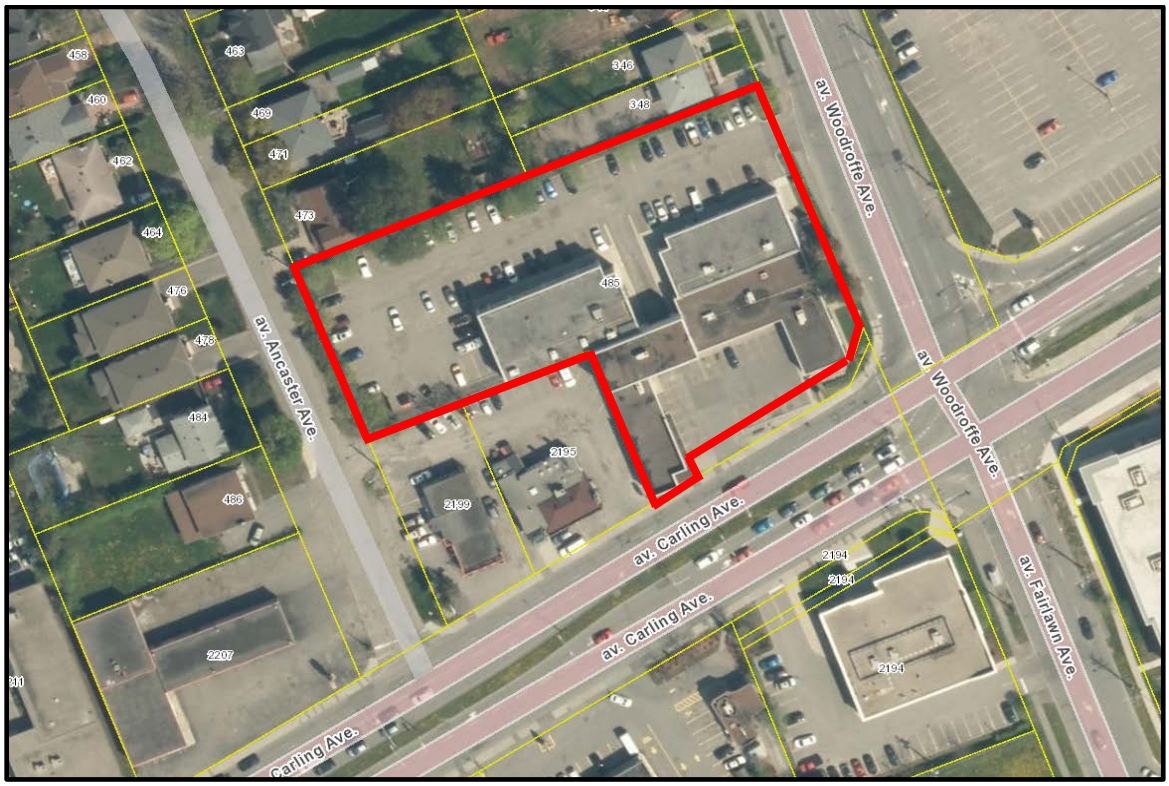
112 MONTREAL ROAD & 314 GARDINER STREET, VANIER

Vendor:	1147310 Ontario Inc.
Purchaser:	2705460 Ontario Inc. (*Anand Aggarwal*)
Registration Date:	August 6, 2019
Consideration:	$8,500,000
PIN:	04237-0019
Legal Description:	Lot 5 & Parts of Lots 6-7, Block 2 on Plan 29, Part of Lots 40-41 & Lot 88 on Plan 49, being Part 1 on Plan 5R-6112, City of Ottawa
Zoning:	TM [2363] F(3.5) S365-h – Traditional Mainstreet Zone
Site Area:	2.85 acres (as per GeoWarehouse)
Price per Square Foot:	$68.41
Price PSF of FSI:	$19.57

Remarks

The property is located on the south side of Montreal Road and the west side of Vanier Parkway, and to the north of McArthur Avenue, in the Vanier neighborhood, in the central eastern part of the City of Ottawa. It is improved with a hotel, Ottawa Plaza Inn, comprised of four two-storey buildings. The site has been purchased primarily for apartment development. Maximum building heights allowed vary between 26 and 187 feet as per site specific Schedule 365, of the zoning By-law. All uses except existing uses are prohibited until the holding symbol is removed. The holding symbol may only be removed until the following have been undertaken: an approved site plan with conditions for ground floor animation including ground level access to units along the central corridor and provision of a public easement to pathways and a private park, an approved road closing and an approved road opening.

Comparable Sale #4



2177 CARLING AVENUE, 356 WOODROFFE AVENUE & 487 ANCASTER AVENUE, OTTAWA

Vendor:	Ogilvie Realty Ltd. (*Camco Acura*)
Purchaser:	Cred GP Inc. (*Colonnade Investment Inc.*)
Registration Date:	March 8, 2018
Consideration:	$5,950,000
PIN:	03967-0138
Legal Description:	Lot 1 on Plan 461, being Parts 1-2 on Plan 4R-13307, Part of Lots 8 on Plan 461, being Part 1 on Plan 4R-1929, City of Ottawa
Zoning:	AM10 – Arterial Mainstreet Zone
Site Area:	62,420 square feet (1.43 acres) (as per GeoWarehouse)
Price per Square Foot:	$95.32
Proposed GFA:	211,159 square feet
Price PSF Proposed GFA:	$28.18

Remarks

This property is located on the north side of Carling Avenue, the west side of Woodroffe Avenue and the east side of Ancaster Avenue, in the Carlingwood neighborhood, in the City of Ottawa. It is improved with a one and two-storey 23,478 square foot retail plaza with a second floor office components. There is a proposed plan for two residential buildings with ground floor retail, one being six-storeys and the other twelve-stories. The building heights are to be 66 feet and 128 feet. The plan proposes 145 one-bedroom and 145 two-bedroom units totaling 290 residential units. The ground floor retail is proposed to be 10,315 square feet. It will have 18 surface and 214 underground parking spaces. It is located within 650 metres of the New Orchard transit station and future LRT station being part of the Confederation Line Extension West set to open in 2025. A zoning amendment is required to permit the maximum height proposed of 128 feet versus that permitted of 98 feet.

OTTAWA CITIZEN BUILDING SALE



1101 BAXTER ROAD, NEPEAN

Vendor:	Postmedia Network Inc.
Purchaser:	Baxter Regional Inc. (*The Regional Group*)
Registration Date:	December 18, 2018
Consideration:	$21,000,000
PIN:	03956-0003
Zoning	IL
Site Area:	7.71 acres (as per GeoWarehouse)
Building Area:	186,000 square feet
Price PSF Building Area:	$113
Price PSF Land Area:	$62.53

Remarks

The property is located on the south side of Baxter Road, to the north of Iris Street and to the east of Greenbank Road, just south of Highway 417, in the Queensview/Morrison Industrial-Office Area of the City of Ottawa. It is improved with a two-storey office building and newspaper production facility that is occupied by the Ottawa Citizen and Ottawa Sun. There is a long-term leaseback agreement between the purchaser and vendor where the purchaser will redevelop 25,000-35,000 square feet and lease it to other tenants. It has three overhead grade-level loading doors. It has approximately 185 paved parking spaces. It will be located within 600 metres of Queensview transit station. A new pedestrian bridge will be constructed and will span Highway 417 from the new Queensview LRT station to Baxter Road, near Ikea.

BOV | Executive Summary

Subject Property: 304 Kennedy Rd, Dryden ON

Prepared for:

ENBRIDGE



Building Size (square feet):	2,000 SF + 174 SF storage building
Year Built:	1979
Land Area:	1.06 acres
Parking:	30 Parking Spaces

SALES COMPS

Address	Comparison	Bldg Size	Sale Price	Price/SF
330 Kennedy Rd	Above Average	3,680 SF	$207,500	$56.39
326 Kennedy Rd	Above Average	3,696 SF	$190,000	$51.41
121 Duke St	Average	2,471 SF	$150,000	$60.70
8 Whyte Ave	Average	1,980 SF	$189,000	$95.45
13748 Hwy 17 E	Average	2,730 SF	$189,000	$69.23
73 Duke St		3,083 SF	$199,000	$64.55
VALUATION SUMMARY - 304 Kennedy Rd				
Comparable Avg. Sale Price/SF:			$177,419	$81.61
Recommended Asking Price per SF (High Value):			**$229,000**	**$105.34**

LISTING COMPS

Address	Comparison	Total Size	Asking Price	Price/SF
33 Hearst Ave	Average	3,600 SF	$199,000	$55.28
21 Duke St	Average	1,268 SF	$219,500	$173.11
31 King St	Average	6,000 SF	$224,900	$37.48

June 3, 2024

JLL






Property Features	Comparable	Comparable	Comparable	Comparable
MLS #	TB210448	TB220796	TB231653	TB232918
Address-House	4 BAKER Road	127 MANITOBA	315 First Street	186 Railway Street
Status	SOLD	SOLD	SOLD	SOLD
List Date	3/4/2021	4/21/2022	6/18/2023	9/20/2023
List Price	$64,900	$59,900	$119,900	$229,900
Sold Price	$40,000	$40,000	$119,900	$216,000
Firm Date	5/11/2021	5/10/2022	7/18/2023	10/10/2023
Days On Market	64	19	28	18
Annual Taxes $	$1,500.00	$5,000.00	$1,800.00	$7,973.00
Style				
Waterfront Name				
Main Floor Area				
Total Above Grade SqFt				
# Total Bedrooms				
Total Baths				
FEATURES INTERIOR				
BASEMENT 1				
BASEMENT FINISH				
Lot Frontage	139.00	144.00	167.00	138.00
Acreage				
Lot Depth	IRREG.	115	0	0
Age				
Garage Y/N				
Public Remarks	LARGE COMMERCIAL BUILDING THAT WAS AN AUTOMOTIVE FUEL STATION. LARGE OFFICE AREA - R/IN BATHROOM FACILITIES - 2 LARGE BAYS NOW USED FOR STORAGE. BIG PROPERTY. ACROSS FROM LAKE SUPERIOR.	LARGE 100' X 30' STEEL BUILDING. TWO BAY GARAGE ON EAST END, CENTER AREA HAS INSULATED AREA AND WASHROOM, WEST END OF BUILDING HAS A LARGE OVERHEAD DOOR. BUILDING HAS PROPANE FORCED AIR HEATERS AS WELL AS RADIENT PROPANE HEATERS.	Opportunity knocks! High exposure on the corner of the Trans Canada Highway & the entrance to Nipigon - this once thriving take-out business similar to an A&W needs a new enthusiastic owner to make it the success it used to be. Once a highly popular ice-cream, burger & shake place that everyone loved to hang out at. Call now or visit www.century21superior.com for more info	Terrific commercial building in Nipigon - 2 car wash bays , office space with large board room & private office & reception area, back workshop with grg dr & separate entrance. Updates include new garage door motors in car wash bay in 2020, 2 new commercial natural gas heaters in car wash area 2022 & 2023, office side shingles 2020, office renos 2017-2019. TVs included. Paved parking lot. Great exposure close to the main business district of Nipigon. Quick possession. Call now. Visit www.century21superior.com for more info and pics.

Disclaimer

The above information is provided by members of TBREB and is from sources believed reliable but should not be relied upon without verification. TBREB assumes no responsibility for its accuracy.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1, page 4

Preamble:

"The identified depreciation error resulted in an overstatement of depreciation expense in both 2024 and 2025. No adjustment is proposed for 2024 as it was a cost of service rebasing year and Earnings Sharing was not applicable."

Question(s):

a) It is unclear to us why earning sharing was not applicable in 2024 and as part of the prior rate plan approved. Please clarify.

b) If earning sharing had been applicable in 2024 what would have been the impact of correcting the depreciation error on that calculation?

Response:

a) As noted previously in the Company's 2024 Utility Earnings and Disposition of Deferral & Variance Account Balances application:

> In its 2024 Rebasing Phase 1 Decision[1], the OEB found that an Earnings Sharing Mechanism for the 2024 Test Year is not required. The OEB stated that it had conducted a thorough review of all Phase 1 Issues in that Application which included extensive discovery and an Oral Hearing to test the evidence and that the OEB is confident that the rates resulting from its Decision are reasonable and appropriately reflect the costs to serve customers.[2]

b) Enbridge Gas was in a gross earnings deficiency versus the earnings sharing threshold in 2024. Had earnings sharing been applicable, there would have been no amount subject to sharing. Correcting this depreciation error would not have resulted in an overall 2024 gross earnings sufficiency subject to earnings sharing. Therefore, had earnings sharing been in place in 2024, there would have been no impact from making this correction.

[1] EB-2022-0200, OEB Decision and Order, December 21, 2023, p.128.
[2] EB-2025-0155, Exhibit B, Tab 1, Schedule 1, p.1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 3, page 1 of 1

Question(s):

What is the main driver for the $5.5 million drop in “Other Operating Revenue” (line 8) in 2025 as compared to 2024?

Response:

Please see response at Exhibit I.FRPO-4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

"As Enbridge Gas's Conditions of Service allow for invoices to be corrected and rebilled up to two years prior, it is expected that rebills will occur back to a period when the Federal Carbon Charge was in place. This may result in a change to bad debt expenses, related to carbon charges, that continue being incurred even though the Federal Carbon Charge has been removed. In addition, there may be changes in collectability of amounts in arrears that could change the bad debt expense related to the Federal Carbon Charge. Therefore, Enbridge Gas will keep the CCBDDA open to capture any potential incremental carbon bad debt expenses that could occur, as well as any bad debt associated with the recovery of Ontario EPS program costs."

Question(s):

Will the 2026 CCBDDA only record amounts resulting from rebillings?

Response:

The 2026 Carbon Charges Bad Debt Deferral Account (CCBDDA) will record carbon bad debt amounts related to billing adjustments for periods prior to April 1, 2025 that occur in 2026 and related to the 2026 Emissions Performance Standards (EPS) facility carbon compliance obligation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 14
EB-2025-0155, Exhibit I.CCC-5

Question(s):

Please provide a table showing the 2025 actual DIMP and EDIMP Administrative costs in the same format as provided in response: EB-2025-0155, Exhibit I.CCC-5, Table 1, page 2 of 2.

Response:

For a breakdown of the Distribution Integrity Management Program (DIMP) and Enhanced Distribution Integrity Management Program (EDIMP) Administrative costs found at Exhibit C, Tab 2, Schedule 14, Table 2, please see Table 1, the same table format as noted in EB-2025-0155, Exhibit I.CCC-5, Table 1, page 2 of 2, updated with 2025 actuals versus the 2025 escalated budget.

Table 1
2025 DIMPVA Administrative Cost Breakdown

Line No.	Particulars	2025 Escalated Budget ($000s)	2025 Actuals ($000s)	Variance ($000s)
	DIMP Admin			
1	FTE Costs	1,211	1,349	138
2	Contingent Worker (CWR) Costs	346	215	(131)
3	Employee Related Services (Training)	7	27	20
4	Professional Dues	2	1	(1)
5	Travel & Accommodation	46	18	(28)
6	Other Admin	3	(49)	(52)
7	DIMP Admin Total	1,615	1,561	(55)
	EDIMP Admin			
8	FTE Costs	803	881	78
9	Contingent Worker (CWR) Costs	218	71	(147)
10	Employee Related Services (Training)	2	0	(2)
11	Professional Dues	1	1	0
12	Travel & Accommodation	3	22	19
14	Other Admin	0	(29)	(29)
15	EDIMP Admin Total	1,027	946	(81)