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Enbridge Gas Inc.
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July 30, 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)
Ontario Energy Board (OEB) File No.: EB-2026-0108
2025 Utility Earnings and Disposition of Deferral & Variance Account Balances Application and Evidence

Effective January 1, 2019, Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union) amalgamated to become Enbridge Gas Inc. Enclosed is the Application and Evidence submitted by Enbridge Gas addressing 2025 utility earnings and the disposition and recovery of certain 2025 deferral and variance account balances (the Application) for all Enbridge Gas rate zones.

Included with the Application, Enbridge Gas is providing the OEB Scorecard, the Integrated Resource Planning (IRP) Annual Report and the IRP Technical Working Group Report, the Indigenous Working Group Report, the Distribution Integrity Management Program and Enhanced Distribution Integrity Management Program Report on Activities, the Storage and Load Balancing Report, and the Brand Clarity Study. No approval is being sought regarding these items.

In accordance with the OEB's Decision in the 2024 Utility Earnings and Disposition of Deferral and Variance Account Balances proceeding[1], Enbridge Gas will be providing a report on Estimated Billing and Meter Reading Performance by the end of August. No approval is being sought regarding this report. This report is for informational purposes and does not impact approvals requested by Enbridge Gas in this application.

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

The Application is supported by evidence which is outlined below:

Exhibit A: Overview and Introduction

Exhibit B: Utility Results

Exhibit C: Enbridge Gas Deferral and Variance Accounts

Exhibit D: EGD Rate Zone Deferral and Variance Accounts

Exhibit E: Union Rate Zones Deferral and Variance Accounts

Exhibit F: Rate Allocation

Exhibit G: Additional Items Not Requiring OEB Approval

Enbridge Gas proposes to dispose of the approved 2025 deferral and variance account balances with the first QRAM application following the OEB's approval.

In accordance with the OEB's revised Practice Direction on Confidential Filings effective December 17, 2021, Enbridge Gas is requesting confidential treatment of the following exhibit – details of the specific confidential information for which confidential treatment is sought (all of which fits within the OEB's "presumptively confidential" category) are set out below:

Exhibit	**Description of Document**	**Brief Description**	**Basis for Confidentiality Claim**
Exhibit D, Tab 2, Schedule 2	Storage RFP Summary	Contains vendor responses for third party storage information including terms, pricing and injection and withdrawal offers.	Meets categories of information to be treated as confidential from third parties as part of a competitive procurement process. Equivalent information has been treated as confidential in previous proceedings, including the Enbridge Gas 2024 Deferral & Variance Account Balances Application (see EB-2025-0155 Decision on Confidentiality, March 4, 2026).

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.

The above noted submission has been filed electronically through the RESS and will be made available on Enbridge Gas's website at:
https://www.enbridgegas.com/Regulatory-Proceedings

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)

EXHIBIT LIST

A – Overview and Introduction

Exhibit	Tab	Schedule	Contents
A	1	1	Exhibit List
	2	1	Application
	3	1	Overview and Approvals Required

B - Utility Results and Earning Sharing

Exhibit	Tab	Schedule	Contents
B	1	1	2025 Earnings Determination Process
		2	Return on Equity
		3	Utility Income
		4	Utility Income Tax and Summary of Capital Cost Allowance
		5	Utility Rate Base and Continuity Schedules
		6	Capital Structure and Cost of Capital
		7	Reconciliation of Audited Income to Corporate
	2	1	Customer Meters, Volumes and Revenues By Rate Class
		2	Revenue from Regulated Storage and Transportation of Gas
		3	Utility Other Revenue and Other Income
	3	1	Operating and Maintenance Expense

B - Utility Results and Earning Sharing

Exhibit	Tab	Schedule	Contents
B	3	2	Utility Capital Expenditures

C - Enbridge Gas Inc Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
C	1	1	Deferral and Variance Actual and Forecast Balances
	2	1	Account No. 179-201 Upstream Transportation Optimization V/A
		2	Account No. 179-202 Transportation from Dawn Service D/A
		3	Account No. 179-203 UFG Volume V/A
		4	Account No. 179-204 UFG Price V/A
		5	Account No. 179-302 Deferral Clearance V/A
		6	Account No. 179-303 Parkway Deliver Obligation V/A
		7	Account No. 179-305 Pension and OPEB V/A
		8	Account No. 179-307 - Facility Carbon Charge V/A
		9	Account No. 179-308 - Customer Carbon Charge V/A
		10	Account No. 179-309 Carbon Charges Bad Debt D/A
		11	Account No. 179- 311 Earnings Sharing Mechanism D/A
		12	Account No. 179-312 - Tax V/A

C - Enbridge Gas Inc Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
C	2	13	Account No. 179-323 Dawn Parkway Surplus Capacity D/A
		14	Account No. 179-326 Distribution Integrity Management Program V/A
		15	Account No. 179-328 Post Retirement True-up V/A
		16	Account No. 179-330 Clean Fuel Regulation Credits D/A
		17	Account No. 179-331 Indigenous Working Group D/A
		18	Account No. 179-333 Average Use V/A
		19	Account No. 179-335 Getting Ontario Connected V/A
		20	Account No. 179-336 Disposition of Property D/A
		21	Account No. 179-338 LEAP Emergency Financial Assistance V/A
		22	Account No. 179-340 OEB Cost Assessment V/A
		23	Account No. 179-341 IRP System Pruning D/A
		24	Accounts not being requested for clearance

D - EGD Rate Zone Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
D	1	1	Account No. 179-88 Storage & Transportation D/A

D - EGD Rate Zone Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
D	2	1	Storage RFP Letter
		2	Storage RFP Summary (Redacted)

E – Union Rate Zones Deferral and Variance Accounts

Exhibit	Tab	Schedule	Contents
E	1	1	Account No. 179-108 Unabsorbed Demand Cost V/A
		2	Account No. 179-70 Short-Term Storage and Other Balancing Services

F – Rate Allocation

Exhibit	Tab	Schedule	Contents
F	1	1	Allocation and Disposition of 2025 Deferral and Variance Account Balances
		2	Summary of Deferral and Variance Account Allocation Factors
		3	Split of EGI Account Balances to Rate Zones
	2	1	EGD – Unit Rate and Type of Service
		2	EGD – Classification and Allocation of Deferral and Variance Account Balances
		3	EGD – Unit Rates for One-Time Adjustment
		4	EGD – Bill Adjustment for Typical Customers
	3	1	Union – Unit Rate and Type of Service

F – Rate Allocation

Exhibit	Tab	Schedule	Contents
F	3	2	Union – Classification and Allocation of Deferral and Variance Account Balances
		3	Union – Unit Rates for One-Time Adjustment
		4	Union – Bill Adjustment for Typical Customers

G – Additional Items Not Requiring OEB Approval

Exhibit	Tab	Schedule	Contents
G	1	1	2025 Scorecard Results
		2	OEB Scorecard 2021 – 2025
		3	Estimated Billing and Meter Reading Performance Report – *To be Filed*
	2	1	IRP Annual Report and IRP Technical Working Group Report
	3	1	Indigenous Working Group Report
	4	1	DIMP/EDIMP Report on Activities
	5	1	Storage and Load Balancing Report
	6	1	Brand Clarity Study

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an order or orders clearing certain commodity and non-commodity related deferral or variance accounts.

APPLICATION

1. The Applicant, Enbridge Gas Inc. (Enbridge Gas) is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting, and storing natural gas within Ontario. Enbridge Gas was formed effective January 1, 2019, upon the amalgamation of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union).

2. On October 31, 2022, Enbridge Gas filed a Cost of Service and Rebasing Application for 2024 rates and for approval of an incentive rate-setting mechanism (IRM) for the following four years under EB-2022-0200. The Ontario Energy Board (OEB) split the Rebasing Application into 3 phases, with Phase 1[1] focused on cost of service rates for 2024, while Phase 2[2] was focused on setting the IRM for 2025 to 2028. Through Decisions and OEB-approved Settlement Agreements for Phase 1 and Phase 2, the OEB approved deferral and variance accounts for Enbridge Gas to be in effect for the 2024 to 2028 IRM term. Some of the deferral and variance accounts relate to Enbridge Gas as a whole, while some apply to either the EGD or Union Rate Zones.[3]

[1] EB-2022-0200.

[2] EB-2024-0111.

[3] "Union rate zones" collectively refers to Union North West, Union North East and Union South.

3. Enbridge Gas hereby applies to the OEB, pursuant to Section 36 of the *Ontario Energy Board Act*, 1998, for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

1. Earnings Sharing

4. The OEB has approved, among other things, an asymmetrical earnings sharing mechanism (ESM) during the IRM term period, where each year any earnings in excess of 100 basis points over the OEB-approved return on equity (ROE) would be shared 50/50 between the Company and ratepayers. Further, earnings over 300 basis points above the allowed ROE will be credited to ratepayers on a 90/10 basis.

5. In 2025, Enbridge Gas's actual utility earnings exceeded the OEB-approved ROE by more than 100 basis points. Accordingly, the ESM amount proposed to be shared with ratepayers is outlined at Exhibit C, Tab 2, Schedule 11.

2. Enbridge Gas Inc.

6. The OEB has approved several deferral and variance accounts that relate to Enbridge Gas as a whole (and not to specific Rate Zone(s)). Enbridge Gas requests approval to clear the final balances of certain Enbridge Gas deferral and variance accounts for 2025 as set out at Exhibit C, Tab 1, Schedule 1.

3. EGD Rate Zone

7. Enbridge Gas requests approval to clear the final balances of certain EGD rate zone deferral and variance accounts for 2025 as set out at Exhibit C, Tab 1, Schedule 1.

8. The final balance in account 179-325 Open Bill Extension Deferral Account was brought forward for disposition in 2024. The program was discontinued as of October 31, 2024, and no balance will be recorded in the account going forward. As such, Enbridge Gas requests that this account be approved for closure.

4. Union Rate Zones

9. Enbridge Gas requests approval to clear the final balances of certain Union rate zones deferral and variance accounts for 2025 as set out at Exhibit C, Tab 1, Schedule 1.

5. Relief Requested

10. Enbridge Gas therefore applies to the OEB for such final, interim or other orders as may be necessary or appropriate for the clearance or disposition of the 2025 deferral and variance accounts requested in Exhibit C, Tab 1, Schedule 1. This includes final disposition of certain accounts previously cleared on an interim basis. The proposed manner of disposition is described at Exhibit F. Enbridge Gas proposes to clear the balances in these accounts with the first available QRAM application following the OEB's approval.

11. Enbridge Gas requests that certain information included at Exhibit D, Tab 2, Schedule 2 be treated as confidential under the OEB's Practice Direction on Confidential Filings. Equivalent information has been treated as confidential in prior deferral and variance account clearance proceedings.

12. Enbridge Gas requests approval to close account 179-325 Open Bill Extension D/A.

13. Enbridge Gas requests that this proceeding be heard in writing.

14. Enbridge Gas further applies to the OEB pursuant to the provisions in the Act and the OEB's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

15. This Application is supported by written evidence. This evidence may be amended from time to time as required by the OEB, or as circumstances may require.

16. The persons affected by this Application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Enbridge Gas, together with those to whom Enbridge Gas sells gas, or on whose behalf Enbridge Gas distributes, transmits or stores gas. It is impractical to set out in this Application the names and addresses of such persons because they are too numerous.

17. Enbridge Gas requests that a copy of every document filed with the OEB in this proceeding be served on the Applicant and Applicant's counsel, as follows:

The Applicant:

Mr. Richard Wathy
Technical Manager, Regulatory Applications
Enbridge Gas Inc.

Address for personal service	Enbridge Gas Inc. P. O. Box 2001 50 Keil Drive North Chatham, ON N7M 5M1
Telephone:	519-365-5376
Email:	Richard.Wathy@enbridge.com EGIRegulatoryproceedings@enbridge.com

- and –

The Applicant's counsel:

Mr. David Stevens
Aird & Berlis LLP

Address for personal service and mailing address:	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	416-863-1500
Email:	dstevens@airdberlis.com

DATED: July 30, 2026, at Chatham, Ontario

ENBRIDGE GAS INC.

Richard Wathy

Richard Wathy
Technical Manager, Regulatory Applications

2025 DEFERRAL ACCOUNT DISPOSITION AND EARNINGS SHARING OVERVIEW AND APPROVALS REQUESTED

1. Enbridge Gas Inc. (Enbridge Gas) is applying to the Ontario Energy Board (OEB) pursuant to Section 36 of the *OEB Act* for approval to dispose and recover certain 2025 deferral and variance account final balances for Enbridge Gas, and the Enbridge Gas Distribution (EGD) and Union Gas (Union)[1] rate zones. Enbridge Gas is also presenting the earnings sharing mechanism (ESM) calculations for the amalgamated utility.

2. The evidence in this Application is organized as follows:
   Exhibit A: Overview and Introduction
   Exhibit B: 2025 Utility Results and Earnings Sharing Amount
   Exhibit C: Enbridge Gas Inc. Deferral and Variance Accounts
   Exhibit D: EGD Rate Zone Deferral and Variance Accounts
   Exhibit E: Union Rate Zones Deferral and Variance Accounts
   Exhibit F: Rate Allocation
   Exhibit G: Additional Items Not Requiring OEB Approval

3. Enbridge Gas proposes that the impacts which result from the disposition of 2025 deferral and variance account balances be implemented with the first available Quarterly Rate Adjustment Mechanism (QRAM) application following the OEB's approval, to align with other rate changes implemented through the QRAM.

1. Relief requested

4. Enbridge Gas requests approval to clear the final balances of certain Enbridge Gas, EGD rate zone, and Union rate zones 2025 deferral and variance accounts. The

[1] "Union rate zones" collectively refers to Union North West, Union North East and Union South.

balances of the 2025 deferral and variance accounts are set out at Exhibit C, Tab 1, Schedule 1. For ease of reference, a copy of Exhibit C, Tab 1, Schedule 1 is attached at Appendix A to this exhibit.

5. Explanations for the balances in each account are set out at Exhibit C (Enbridge Gas), Exhibit D (EGD rate zone) and Exhibit E (Union rate zones). The evidence also indicates which accounts Enbridge Gas does not seek to clear in this proceeding. The proposed clearance methodology for the accounts being cleared is set out at Exhibit F.

2. Disposition of deferral and variance accounts

6. Integration of the legacy billing systems for EGD and Union Gas enables Enbridge Gas to dispose of balances in the 2025 deferral and variance accounts as a one-time adjustment for all customers. Enbridge Gas proposes to dispose of the 2025 deferral and variance accounts as a one-time adjustment for all general service, in-franchise contract and ex-franchise rate classes.

7. The proposed approach to the one-time adjustment is consistent between the EGD and Union rate zones and, subject to OEB approval as to timing, will be disposed of with the first available QRAM application.

3. 2024 Upstream Transportation Optimization Variance Account and Union Rate Zones Unabsorbed Demand Costs Variance Account final disposition

8. In the 2024 Utility Earnings and Disposition of Deferral and Variance, Decision and Order, the OEB approved the disposition of the Upstream Transportation Optimization V/A and Unabsorbed Demand Costs V/A on an interim basis, to provide parties the opportunity to ask follow-up clarification questions.[2] Upon addressing the

[2] EB-2025-0155, Decision and Order, p.7.

follow-up clarification questions, Enbridge Gas requests that the prior interim disposition of these accounts be declared final.

4. Open Bill Extension Deferral Account closure request

9. The final balance in the account was brought forward for disposition in the 2024 Utility Earnings and Disposition of Deferral and Variance Account proceeding.[3] The program was discontinued as of October 31, 2024, and no balance will be recorded in the account going forward. As such, Enbridge Gas requests that this account be approved for closure.

[3] EB-2025-0155, Exhibit D, Tab 1, Schedule 2.

Enbridge Gas
Deferral & Variance Account
Actual & Forecast Balances

Line No.	Account Description	OEB Account Number	Col. 1 Forecast for clearance at July 1, 2027 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Total ($000's)	Col.4 Reference to Evidence
	EGI Commodity Related Accounts					
1.	Upstream Transportation Optimization V/A	179-201	(34,774.9)	(1,882.5)	(36,657.4)	Exhibit C-2-1
2.	UFG Volume V/A	179-203	10,558.8	408.1	10,966.9	Exhibit C-2-3
3.	UFG Price V/A	179-204	(3,557.1)	(138.2)	(3,695.4)	Exhibit C-2-4
4.	Total Commodity Related Accounts		(27,773.2)	(1,612.6)	(29,385.8)	
	EGI Non Commodity Related Accounts					
5.	Transportation from Dawn Service D/A	179-202	70.4	3.7	74.0	Exhibit C-2-2
6.	Deferral Clearing V/A	179-302	3,529.2	174.3	3,703.5	Exhibit C-2-5
7.	Parkway Delivery Obligation V/A	179-303	2,558.2	129.5	2,687.7	Exhibit C-2-6
8.	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	
9.	Pension & OPEB V/A	179-305	-	(4,909.1)	(4,909.1)	Exhibit C-2-7
10.	Facility Carbon Charge V/A	179-307	(742.7)	(99.8)	(842.4)	Exhibit C-2-8
11.	Customer Carbon Charge V/A	179-308	(2.1)	(0.2)	(2.2)	Exhibit C-2-9
12.	Carbon Charges Bad Debt D/A	179-309	6,948.4	417.7	7,366.1	Exhibit C-2-10
13.	Earnings Sharing Mechanism D/A	179-311	(24,300.0)	(932.7)	(25,232.7)	Exhibit C-2-11
14.	Tax V/A	179-312	(13,621.5)	(347.3)	(13,968.8)	Exhibit C-2-12
15.	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	
16.	Green Button Initiative D/A	179-320	-	-	-	
17.	Dawn Parkway Surplus Capacity D/A	179-323	(2,260.3)	(105.1)	(2,365.4)	Exhibit C-2-13
18.	Distribution Integrity Management Program D/A	179-326	213.0	12.2	225.2	Exhibit C-2-14
19.	Post Retirement True-Up V/A	179-328	(49,006.6)	(2,542.6)	(51,549.2)	Exhibit C-2-15
20.	Clean Fuel Regulation Credits D/A	179-330	(35.0)	(1.8)	(36.9)	Exhibit C-2-16
21.	Indigenous Working Group D/A	179-331	268.6	12.1	280.7	Exhibit C-2-17
22.	Cloud Computing Implementation Costs D/A	179-332	-	-	-	
23.	Average Use V/A	179-333	34,494.4	2,130.6	36,625.0	Exhibit C-2-18
24.	Getting Ontario Connected V/A	179-335	14,093.7	744.7	14,838.3	Exhibit C-2-19
25.	Disposition of Property D/A	179-336	(12,804.0)	(689.4)	(13,493.4)	Exhibit C-2-20
26.	LEAP Emergency Financial Assistance D/A	179-338	1,200.8	50.6	1,251.4	Exhibit C-2-21
27.	OEB Cost Assessment V/A	179-340	2,997.0	121.9	3,118.9	Exhibit C-2-22
28.	IRP System Pruning D/A (2024 & 2025)	179-341	388.0	26.9	414.9	Exhibit C-2-23
29.	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-	
30.	Total Non Commodity Related Accounts		(36,010.5)	(5,803.8)	(41,814.3)	
31.	Total EGI Accounts (for clearance)		(63,783.8)	(7,416.4)	(71,200.1)	
	EGD Rate Zone Commodity Related Accounts					
32.	Storage and Transportation D/A	179-88	3,126.8	276.9	3,403.8	Exhibit D-1-1
33.	Total Commodity Related Accounts		3,126.8	276.9	3,403.8	
	EGD Rate Zone Non Commodity Related Accounts					
34.	Open Bill Extension D/A	179-325	-	-	-	
35.	Total Non Commodity Related Accounts		-	-	-	
36.	Total EGD Rate Zone (for clearance)		3,126.8	276.9	3,403.8	
	Union Rate Zones Gas Supply Accounts					
37.	Unabsorbed Demand Costs Variance Account	179-108	4,881.6	240.3	5,121.9	Exhibit E-1-1
38.	Total Gas Supply Accounts		4,881.6	240.3	5,121.9	
	Union Rate Zones Storage Accounts					
39.	Short-Term Storage and Other Balancing Services	179-70	(599.3)	(22.9)	(622.2)	Exhibit E-1-2
40.	Total Storage Accounts		(599.3)	(22.9)	(622.2)	
41.	Total Union Rate Zones (for clearance)		4,282.3	217.4	4,499.7	
42.	Total Deferral and Variance Accounts (for clearance)		(56,374.6)	(6,922.0)	(63,296.6)	
	EGI Accounts Not Being Requested For Clearance					
43.	Incremental Capital Module D/A	179-306	-	-	-	
44.	IRP Operating Costs Deferral Account	179-318	2,234.6	100.0	2,334.6	Exhibit C-2-24
45.	IRP Capital Costs Deferral Account	179-319	(3.0)	(0.1)	(3.1)	Exhibit C-2-24
46.	Panhandle Region Expansion Project V/A (2024-2025)	179-329	(10,199.5)	(643.5)	(10,843.0)	Exhibit C-2-24
47.	Site Restoration Costs Tracking Account	179-337	(15,615.7)	-	(15,615.7)	Exhibit C-2-24
48.	Asset Life Extension Costs D/A	179-343	-	-	-	

2025 ENBRIDGE GAS INC. EARNINGS DETERMINATION PROCESS

1. For the year ended December 31, 2025, Enbridge Gas Inc. (Enbridge Gas, or the Company) is in an earnings sharing position, as its achieved return on equity was higher than the threshold required for sharing. The earnings sharing calculation is shown at Exhibit B, Tab 1, Schedule 2 while supporting schedules that show the calculation of utility rate base, utility income and taxes, and the utility capital structure components, are contained in the balance of the B Exhibits. Exhibit B, Tab 1, Schedule 7 sets out a reconciliation of audited income to corporate income.

2. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the 2024 Rebasing Phase 1[1] OEB Decision and Order, dated December 21, 2023:
    - if in any calendar year during the deferred rebasing term, Enbridge Gas's actual utility ROE is more than 100 basis points above the OEB-approved ROE for that year, then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge Gas and its ratepayers;
    - further, earnings over 300 basis points above the allowed ROE will be credited to ratepayers on a 90/10 basis;
    - the allowed ROE to be used for earnings sharing purposes is the ROE embedded in base rates, which is 9.21%;
    - for the purposes of the Earnings Sharing Mechanism (ESM), Enbridge Gas shall calculate its earnings using generally accepted accounting principles (GAAP) consistent with its external reporting, including the regulatory rules prescribed by the OEB from time to time;

[1] EB-2020-0200.

- all revenues and costs that would otherwise be included in a cost of service application shall be included in the earnings sharing calculation.

3. Within Exhibit B, Tab 1, Schedule 2, the Company has calculated earnings for sharing. Column 2 within the exhibit provides references indicating where additional evidence in support of the determination of the amounts in the calculation can be found. Column 3 contains results shown in millions of dollars, or percentages.

Return on Equity

4. Net utility income applicable to common equity is first determined.

5. The $1,250.0 million (line 2) of utility income before income tax, less long term debt, short term debt and preference share costs, and utility income taxes, produces the $683.6 million of net income applicable to common equity (line 8).

6. The $683.6 million, divided by the deemed common equity level of $6,345.0 million (line 9, calculated as 38% of the $16,697.4 million rate base) produces a return on equity of 10.774% (line 11). When comparing the 10.774% achieved return on equity to the OEB-approved 2025 ESM threshold percentage of 10.21% (line 10), there is a sufficiency in ROE of 0.564% (line 12).

7. The 0.564% multiplied by the common equity level of $6,345.0 million produces a net over earnings or sufficiency of $35.8 million, which from a pre-tax perspective ($35.8 million divided by the reciprocal, 73.5%, of the corporate tax rate), results in a $48.7 million gross amount of over earnings (line 15), to be shared equally between ratepayers and the Company.

3. Process Description

8. The calculation of utility earnings starts with financial results contained within the Enbridge Gas corporate trial balance. The Company notes that the corporate trial

balance includes the elimination of transactions between each of the rate zones. This predominantly relates to the elimination of regulated and unregulated storage and transmission revenues that would have been reflected in the Union rate zones, offset by a corresponding elimination of gas costs that would have been reflected for the EGD rate zone. This reflects the fact that from a corporate perspective, EGD rate zone delivery revenues are contributing to the costs of Union rate zones regulated and unregulated storage and transmission services.

9. From there, in order to calculate the utility rate base, income, and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the OEB and the standards associated with cost of service rate related accounting processes. Examples are:

    - Determination of rate base amounts using the average of monthly averages value concept,
    - Elimination of corporate interest expense due to the treatment of interest expense as embedded in the capital structure balanced to rate base; and,
    - Elimination of corporate income taxes due to the determination of income taxes specific to utility results.

10. In addition, Enbridge Gas has made the appropriate adjustments in relation to non-standard rate regulated items which the OEB has either decided in the past or are required in order to determine an appropriate utility return on equity. Examples are:

    - Exclusion of non-utility or unregulated activities;
    - Elimination of approved shareholder incentives (such as Demand Side Management incentives, amounts related to short-term storage, and net optimization incentives);
    - Elimination of the shareholder portion of gains on property dispositions; and

- Elimination of Central Functions Corporate Cost Allocation Methodology (CFCAM) charges that did not pass the 3-prong test[2].

11. Further to the adjustments noted above, Enbridge Gas has reflected an adjustment to utility depreciation expense for 2025 in relation to an error identified in depreciation expense. In Q2 2026, a depreciation error was identified that resulted in an overstatement of utility depreciation expense for 2024 and 2025 as follows: 2024 - $14.5 million and 2025 - $2.8 million.

12. In Q2 2026 Enbridge Gas recognized and recorded the adjustment as an increase to net property, plant and equipment (through a reduction in accumulated depreciation) and a reduction to depreciation expense. 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. For 2025, the impact is reflected in the ESM calculation to ensure that earnings are measured on a basis consistent with OEB rate making principles.

13. For 2025, the depreciation adjustment of $2.8 million, as part of utility income, is reflected in Exhibit B, Tab 1, Schedule 3, column 3, line 9 as part of the utility adjustment. 2025 accumulated depreciation included as part of rate base, has also been adjusted to reflect the correction of 2024 and 2025 depreciation impacts, at Exhibit B, Tab 1, Schedule 5, page 4, line 39.

14. Additionally, Enbridge Gas has provided as a utility adjustment the elimination of 2023 Getting Ontario Connected Variance Account disallowance. In its Decision and Order in EB-2024-0125, dated September 23, 2025, the OEB disallowed the $3 million related to incremental VMS program costs from the balance to be

[2] The adjustments were described initially in EB-2022-0200, Exhibit 4, Tab 4, Schedule 3, Attachment 3, Table 6-3.

recovered from customers through disposition of this variance account. Enbridge Gas reflected the disallowance as a write-off (or reversal of deferral treatment) in its 2025 Corporate financial results. However, given that the disallowed amount pertained to 2023 Enbridge Gas' utility results, where Enbridge Gas was not in an earnings sharing position, it has been removed from 2025 utility results.

Summary
Return on Equity
Enbridge Gas Inc.

For The Year Ended December 31, 2025

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual
1	Return on Equity & Revenue (Deficiency) / Sufficiency		
2	Utility Income before Income Tax	(Ex. B, Tab 1, Sch. 3)	1,250.0
3	Less: Long Term Debt Costs	(Ex. B, Tab 1, Sch. 6)	410.8
4	Less: Short Term Debt Costs	(Ex. B, Tab 1, Sch. 6)	14.0
5	Less: Cost of Preferred Capital	(Ex. B, Tab 1, Sch. 6)	0.0
6	Net Income before Income Taxes		825.2
7	Less: Income Taxes	(Ex. B, Tab 1, Sch. 4)	141.5
8	Net Income Applicable to Common Equity	(line 6 - line 7)	683.6
9	Common Equity	(Ex. B, Tab 1, Sch. 6)	6,345.0
10	Approved ROE (including deadband before earning sharing) %	(Board-approved + 100bp)	10.210%
11	Achieved Rate of Return on Equity %	(line 8 / line 9)	10.774%
12	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.564%
13	Net Earnings (Deficiency) / Sufficiency	(line 9 x line 12)	35.8
14	Provision for Income Taxes		12.9
15	Gross Earnings (Deficiency) / Sufficiency	(line 13 / 73.5%)	48.7
16	50% Earnings sharing to ratepayers	(if line 15 > 1, line 15 x 50%)	24.3

EGI Utility Income
2025 Actual

Line No.	Particulars	Reference	Col. 1 Corporate (a)	Col. 2 Unregulated Operations (b)	Col. 3 Adjustments (c)	Col. 4 Utility Income (d) = (a)-(b)+(c) ($Millions)
1	Gas sales and distribution	(Ex. B, Tab 2, Sch. 1)	5,546.4	-	(3.0) (i)	5,543.4
2	Transportation	(Ex. B, Tab 2, Sch. 2)	169.7	(1.2)	(5.6) (ii)	165.3
3	Storage	(Ex. B, Tab 2, Sch. 2)	326.8	326.8	(0.1) (iii)	(0.0)
4	Other operating revenue	(Ex. B, Tab 2, Sch. 3)	69.7	7.1	(10.8) (iv)	51.8
5	Other income	(Ex. B, Tab 2, Sch. 3)	13.8	(0.1)	(8.8) (viii)	5.1
6	Total operating revenue		6,126.3	332.6	(28.2)	5,765.5
7	Gas costs		2,660.7	103.5	5.9 (ix)	2,563.2
8	Operation and maintenance	(Ex. B, Tab 3, Sch. 1)	1,089.3	27.0	(14.3) (v)	1,048.0
9	Depreciation and amortization expense		808.2	19.2	(25.3) (vi)	763.8
10	Fixed financing costs		2.2	-	1.8 (vii)	4.0
11	Municipal and other taxes		139.2	2.7	-	136.4
12	Cost of service		4,699.6	152.2	(31.8)	4,515.5
13	Utility income before income taxes					1,250.0
14	Income tax expense	(Ex. B, Tab 1, Sch. 4)				141.5
15	Utility income					1,108.5

Notes on Adjustments:

(i)	Elimination of the UGL rate zone unregulated storage cost from EGD rate zone revenues	(14.7)
	2025 TVDA adjustment to reflect retroactive Bill C-15 enacted in 2026	(13.6)
	Elimination of ESM amount booked in 2025	25.3
		(3.0)
(ii)	Elimination of the shareholder portion of net optimization activity (before tax)	(5.6)
(iii)	Elimination of the Union rate zone shareholder portion of net short-term storage revenue (before tax)	(0.1)
(iv)	Elimination of demand-side management incentive	(10.8)
(v)	Elimination of donations	(3.1)
	Elimination of 2023 Getting Ontario Connected Variance Account disallowance	(3.0)
	Adjust for 2025 DSMVA correction recognized subsequent to year end Corporate financial statements	0.9
	Elimination of Central Functions Corporate Allocation Methodology (CFCAM) charges	(9.1)
		(14.3)
(vi)	Eliminate amortization of PPD (purchase price discrepancy)	(22.5)
	Adjust for 2025 depreciation correction recognized subsequent to year end Corporate financial statements	(2.8)
		(25.3)
(vii)	Interest on security deposits held during the year and included in elimination of corporate interest exp. Expense incurred to reduce bad debt. The average amount of the security deposit held during the year is applied as a reduction to the allowance for working capital in rate base	1.8
(viii)	Elimination of interest income from investments not included in utility rate base	(0.4)
	Elimination of the portion of gains on sale of assets not shared through deferral	(8.5)
		(8.8)
ix)	Adjust for 2025 S&TDA correction recognized subsequent to year end Corporate financial statements	5.9

Calculation of EGI Utility Taxable Income and Income Tax Expense
2025 Actual

Line No.	Particulars	Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1	Utility income before income taxes	1,250.0	1,250.0	
	Add			
2	Depreciation and amortization	763.8	763.8	
3	Accrual based pension and OPEB costs	(51.1)	(51.1)	
4	Other non-deductible items	2.6	2.6	
5	Total Add Back	715.3	715.3	
6	Sub-total	1,965.3	1,965.3	
	Deduct			
7	Capital cost allowance	881.1	881.1	
8	Items capitalized for regulatory purposes	125.7	125.7	
9	Amortization of share/debenture issue expense	(0.1)	(0.1)	
10	Amortization of C.D.E. and C.O.G.P.E	0.0	0.0	
11	Other	(2.6)	(2.6)	
12	Cash based pension and OPEB costs	2.2	2.2	
13	Total Deduction	1,006.4	1,006.4	
14	Taxable income	959.0	959.0	
15	Income tax rates	15.00%	11.50%	
16	Tax provision excluding interest shield	143.8	110.3	254.1
	Tax shield on interest expense			
17	Rate base	16,697.4		
18	Return component of debt	2.54%		
19	Interest expense	424.8		
20	Combined tax rate	26.50%		
21	Income tax credit			(112.6)
22	Total utility income taxes			141.5

Enbridge Gas Inc.
Summary of Capital Cost Allowance (CCA)

Line No.	Class	Particulars ($000s)	Col. 1 UCC at Prior Year Filing EB-2025-0155 (a)	Col. 2 True-up from Filing to Tax Return (b)	Col. 4 UCC At Beginning of Year (d)	Col. 5 Total Additions Qualifying for RIIP (e)	Col. 5 Total Additions Not Qualifying for RIIP (f)	Col. 6 Less: Lessor of Cost or Proceeds (g)	Col. 7 Eligible CCA Additions (h)	Col 8 Depreciable UCC Balance (i)	Col. 9 Rate (%) (j)	Col. 10 CCA FY2025 (k) = (i) x (j)	Col. 11 Ending UCC (l) = (d) + (e) + (f) + (g) - (k)
1	1	Buildings, structures and improvements, services, meters, mains	2,024,265.4	(29,249.2)	1,995,016.2	2,898.7	2,229.0	(4,922.1)	205.7	1,994,210.2	4%	79,768.4	1,915,453.5
2	1	Non-residential building acquired after March 19, 2007	165,851.4	28,651.9	194,503.3	48,028.8	26,551.7	-	74,580.5	293,098.3	6%	17,585.9	251,498.0
3	2	Mains acquired before 1988	120,129.3	-	120,129.3	-	-	-	-	120,129.3	6%	7,207.8	112,921.6
4	3	Buildings acquired before 1988	2,441.0	-	2,441.0	-	-	-	-	2,441.0	5%	122.0	2,318.9
5	6	Other buildings	51.4	-	51.4	-	-	-	-	51.4	10%	5.1	46.2
6	7	Compression equipment acquired after February 22, 2005	268,305.6	(3.0)	268,302.6	23,824.6	9,392.2	-	33,216.9	313,431.7	15%	47,014.8	254,504.7
7	8	Compression assets, office furniture, equipment	203,686.1	(163.7)	203,522.4	101,541.1	105,327.2	-	206,868.3	461,161.3	20%	92,232.3	318,158.5
8	10	Transportation, computer equipment	24,451.0	3.8	24,454.8	11,279.2	6,494.1	(753.0)	17,020.3	46,738.2	30%	14,021.5	27,453.6
9	12	Computer software, small tools	-	-	-	7,310.4	5,547.4	-	12,857.9	12,857.9	100%	12,857.9	-
10	13	Leasehold improvements	-	15.5	15.5	-	-	-	-	15.5		1.0	14.4
11	14.1	Intangibles	15,036.3	(145.8)	14,890.4	3,556.1	1,095.3	-	4,651.5	21,320.0	5%	1,066.0	18,475.9
12	14.1	Intangibles (pre 2017)	34,992.5	128.7	35,121.2	-	-	-	-	35,121.2	7%	2,458.5	32,662.8
13	17	Roads, sidewalk, parking lot or storage areas	360.1	-	360.1	-	-	-	-	360.1	8%	28.8	331.3
14	38	Heavy work equipment	8,992.1	1.1	8,993.2	3,709.6	2,129.0	(158.8)	5,679.8	16,448.5	30%	4,934.5	9,738.5
15	41	Storage assets	111,178.6	6.9	111,185.5	7,804.6	2,814.4	-	10,619.0	125,706.8	25%	31,426.7	90,377.8
16	45	Computers - Hardware acquired after March 22, 2004	0.6	-	0.6	-	-	-	-	0.6	45%	0.3	0.3
17	49	Transmission pipeline additions acquired after February 23, 2005	1,284,328.0	(16.3)	1,284,311.8	21,037.1	73,157.4	-	94,194.5	1,389,024.8	8%	111,122.0	1,267,384.3
18	50	Computers hardware acquired after March 18, 2007	11,952.5	(2,110.4)	9,842.1	10,052.2	4,348.1	-	14,400.2	29,268.4	55%	16,097.6	8,144.7
19	51	Distribution pipelines acquired after March 18, 2007	6,190,190.6	3,556.5	6,193,747.1	588,965.0	259,225.2	(394.9)	847,795.2	7,335,827.4	6%	443,149.0	6,598,393.4
20	Total		10,466,212.5	676.0	10,466,888.5	830,007.5	498,311.0	(6,228.7)	1,322,089.8	12,197,212.5		881,100.0	10,907,878.3

EGI Utility Rate Base
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 2025 Actual	Col. 2 2024 Actual	Col. 3 Variance
	Property, Plant, and Equipment			
1	Gross property, plant, and equipment	25,349.4	24,298.0	1,051.3
2	Accumulated depreciation	(9,311.2)	(8,839.3)	(471.9)
3	Net property, plant, and equipment	16,038.2	15,458.7	579.5
	Allowance for Working Capital			
4	Materials and supplies	152.5	128.5	24.0
5	ABC receivable	(22.2)	(17.5)	(4.7)
6	Customer security deposits	(64.3)	(65.8)	1.5
7	Prepaid expenses	-	6.7	(6.7)
8	Gas in storage	624.6	609.6	15.0
9	Working cash allowance	(31.3)	(94.9)	63.6
10	Total Working Capital	659.2	566.6	92.7
11	Utility Rate Base	16,697.4	16,025.3	672.1

EGI Utility Property, Plant, and Equipment
Summary Statement - Average of Monthly Averages
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
1	Underground storage plant	1,616.0	(571.6)	1,044.4
2	Transmission plant	5,328.8	(1,854.0)	3,474.8
3	Distribution plant	17,576.5	(6,452.5)	11,124.0
4	General plant	781.2	(408.9)	372.4
5	Local storage plant	43.5	(20.9)	22.6
6	Intangible plant	3.3	(3.3)	
7	EGI Total	25,349.4	(9,311.2)	16,038.2

EGI Utility Gross Plant
Year End Balances and Average of Monthly Averages
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 Opening Balance Dec.2024	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2025	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2025	Col. 7 Average of Monthly Averages
	Underground Storage Plant - EGI							
1	Land (450)	18.4	4.8	-	23.3	(1.0)	22.3	17.6
2	Land rights (451)	74.8	-	(0.5)	74.3	-	74.3	74.4
3	Structures and improvements (452)	142.5	7.7	-	150.2	(0.1)	150.1	142.7
4	Wells (453)	154.8	6.0	(0.1)	160.7	-	160.7	156.3
5	Well equipment (454)	16.9	0.3	(0.0)	17.1	-	17.1	17.1
6	Field Lines (455)	229.3	4.5	(0.0)	233.8	-	233.8	232.6
7	Compressor equipment (456)	673.9	17.2	-	691.1	(0.5)	690.6	674.9
8	Measuring and regulating equipment (457)	222.5	2.4	-	224.9	-	224.9	224.6
9	Base pressure gas (458)	75.7	-	-	75.7	-	75.7	75.7
10	Sub-Total	1,608.8	42.9	(0.6)	1,651.1	(1.5)	1,649.6	1,616.0
	Transmission Plant - EGI							
11	Land (460)	87.7	7.1	-	94.8	-	94.8	89.7
12	Land Rights (461.001)	91.7	4.5	-	96.2	-	96.2	95.6
13	Structures & improvements (462/463/464)	187.8	1.2	-	189.0	-	189.0	188.0
14	Mains (465)	3,297.8	25.8	7.7	3,331.3	-	3,331.3	3,299.7
15	Compressor equipment (466)	1,041.3	15.1	-	1,056.4	-	1,056.4	1,045.1
16	Measuring & regulating equipment (467)	563.9	120.6	-	684.6	-	684.6	584.9
17	Meters (478)	25.7	-	-	25.7	-	25.7	25.7
18	Line Pack Gas	0.2	0.0	-	0.2	-	0.2	0.2
19	Sub-Total	5,296.1	174.3	7.7	5,478.1	-	5,478.1	5,328.8
	Distribution Plant - EGI							
20	Renewable Natural Gas (461)	18.6	-	-	18.6	-	18.6	18.6
21	Land (470)	103.9	0.9	(0.3)	104.5	-	104.5	104.5
22	Land rights (471)	66.8	0.2	-	67.0	-	67.0	66.9
23	Structures and improvements (472)	355.9	81.4	(19.7)	417.7	(0.3)	417.3	386.4
24	Services - metallic (473)	655.6	45.9	(3.2)	698.3	-	698.3	679.4
25	Services - plastic (473)	5,198.6	243.8	(9.9)	5,432.5	-	5,432.5	5,299.8
26	Regulators (474)	515.7	50.5	(12.7)	553.4	-	553.4	540.1
27	Mains - metallic (475)	4,012.5	218.3	(6.5)	4,224.2	(2.2)	4,222.0	4,042.4
28	Mains - plastic (475)	3,946.9	146.2	(0.7)	4,092.4	-	4,092.4	3,990.9
29	NGV station compressors (476)	11.1	(0.0)	-	11.1	-	11.1	11.3
30	Measuring and regulating equip. (477)	1,150.9	45.7	(2.4)	1,194.1	(0.5)	1,193.6	1,164.3
31	Meters (478)	1,236.6	109.0	(36.9)	1,308.8	-	1,308.8	1,271.8
32	Sub-Total	17,273.2	941.9	(92.5)	18,122.6	(3.1)	18,119.5	17,576.5
	General Plant - EGI							
33	Investment in leased assets (101)	16.3	-	-	16.3	-	16.3	16.3
34	Land (480)	0.5	-	-	0.5	-	0.5	0.5
35	Structure & Improvements (482)	232.8	0.0	(3.9)	229.0	(0.2)	228.8	231.3
36	Office furniture and equipment (483)	28.7	0.1	(1.4)	27.4	-	27.4	28.1
37	Transportation equipment (484)	152.2	18.2	(6.1)	164.4	(0.1)	164.3	156.1
38	NGV conversion kits (484)	3.1	-	-	3.1	-	3.1	3.1
39	Heavy work equipment (485)	56.8	6.0	(0.6)	62.3	-	62.3	58.6
40	Tools and work equipment (486)	62.8	10.4	(0.2)	72.9	-	72.9	65.6
41	Rental equipment (487)	2.7	-	-	2.7	-	2.7	2.7
42	NGV rental compressors (487)	9.0	0.0	-	9.0	-	9.0	9.0
43	NGV cylinders (484 and 487)	0.6	-	-	0.6	-	0.6	0.6
44	Communication structures & equip. (488)	1.9	0.0	-	1.9	-	1.9	1.9
45	Computer equipment (490)	30.7	12.0	(8.8)	34.0	-	34.0	28.1
46	Software Aquired/Developed (491)	117.0	16.3	(24.0)	109.3	-	109.3	142.8
47	WAMS (489)	66.3	-	-	66.3	-	66.3	36.4
48	Sub-Total	781.5	63.1	(44.9)	799.7	(0.3)	799.4	781.2
	Intangible Plant - EGI							
49	Inactive services (102)	1.7	-	-	1.7	-	1.7	1.7
50	Franchises and consents (401)	1.2	-	-	1.2	-	1.2	1.2
51	Other intangible plant (402)	0.5	-	-	0.5	-	0.5	0.5
52	Sub-Total	3.3	-	-	3.3	-	3.3	3.3
	Local Storage Plant - EGI							
53	Land (440)	0.0	-	-	0.0	-	0.0	0.0
54	Structures and improvements (442)	7.4	0.8	-	8.2	-	8.2	7.8
55	Gas holders - storage (443)	7.0	0.2	-	7.2	-	7.2	7.1
56	Gas holders - equipment (443)	28.5	0.2	-	28.7	-	28.7	28.6
57	Sub-Total	42.9	1.2	-	44.1	-	44.1	43.5
58	EGI Total	25,005.8	1,223.4	(130.2)	26,098.9	(4.8)	26,094.1	25,349.4

EGI Utility Plant
Continuity of Accumulated Depreciation
Year End Balances And Average of Monthly Averages
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 Opening Balance Dec.2024	Col. 2 Depreciation	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Net SRCVA	Col. 6 Adjustments & Other	Col. 7 Closing Balance Dec.2025	Col. 8 Regulatory Adjustment	Col. 9 Utility Balance Dec.2025	Col. 10 Average of Monthly Averages
	Underground Storage Plant - EGI										
1	Land and gas storage rights (451)	(49.3)	(1.1)	0.5	-	-	-	(49.8)	-	(49.8)	(49.4)
2	Structures and improvements (452)	(68.2)	(3.7)	-	0.0	0.3	(0.0)	(71.6)	0.1	(71.5)	(69.8)
3	Wells (453)	(59.0)	(6.4)	0.1	0.2	1.4	(0.0)	(63.8)	-	(63.8)	(61.4)
4	Well equipment (454)	(10.4)	(0.2)	0.0	-	-	-	(10.5)	-	(10.5)	(10.5)
5	Field Lines (455)	(92.6)	(5.5)	0.0	0.0	0.6	(0.1)	(97.5)	-	(97.5)	(95.0)
6	Compressor equipment (456)	(212.3)	(16.3)	-	1.8	(0.5)	0.1	(227.1)	0.3	(226.8)	(219.4)
7	Measuring and regulating equipment (457)	(63.5)	(5.6)	-	2.3	(1.2)	(0.0)	(68.0)	-	(68.0)	(66.1)
8	Sub-Total	(555.2)	(38.6)	0.6	4.3	0.6	(0.1)	(588.4)	0.4	(588.0)	(571.6)
	Transmission Plant - EGI										
9	Land rights (461)	(22.8)	(1.2)	-	-	-	-	(23.9)	-	(23.9)	(23.3)
10	Structures and improvements (462)	(63.0)	(4.3)	-	0.0	0.3	(0.0)	(67.0)	-	(67.0)	(65.0)
11	Mains (465)	(1,092.8)	(46.7)	(7.7)	2.0	4.6	9.2	(1,131.4)	-	(1,131.4)	(1,112.0)
12	Compressor equipment (466)	(429.4)	(34.4)	-	0.0	1.5	(0.2)	(462.4)	-	(462.4)	(445.8)
13	Measuring and regulating equipment (467)	(200.8)	(16.0)	-	0.6	0.8	0.5	(214.8)	-	(214.8)	(207.9)
14	Sub-Total	(1,808.8)	(102.6)	(7.7)	2.7	7.2	9.5	(1,899.6)	-	(1,899.6)	(1,854.0)
	Distribution Plant - EGI										
15	Renewable Natural Gas (461)	(1.5)	-	-	-	-	-	(1.5)	-	(1.5)	(1.5)
16	Land rights (471)	(15.0)	(1.1)	-	-	-	-	(16.1)	-	(16.1)	(15.5)
17	Structures and improvements (472)	(114.2)	(14.0)	19.7	(2.6)	-	(0.1)	(111.1)	0.3	(110.8)	(108.5)
18	Services - metallic (473)	(405.9)	(22.2)	2.8	(17.6)	22.5	(0.1)	(420.4)	-	(420.4)	(415.1)
19	Services - plastic (473)	(1,606.1)	(152.0)	10.3	99.2	(63.7)	0.5	(1,711.8)	-	(1,711.8)	(1,660.9)
20	Regulators (474)	(192.3)	(48.0)	12.7	0.6	(0.6)	(1.0)	(228.6)	-	(228.6)	(216.0)
21	Mains - metallic (475)	(1,515.7)	(105.2)	6.5	(1.9)	25.1	(8.5)	(1,599.6)	2.2	(1,597.4)	(1,554.2)
22	Mains - plastic (475)	(1,353.3)	(77.2)	0.7	4.6	9.9	(0.3)	(1,415.5)	-	(1,415.5)	(1,384.3)
23	NGV station compressors (476)	(6.6)	(0.4)	-	-	-	-	(6.9)	-	(6.9)	(6.8)
24	Measuring and regulating equip. (477)	(426.4)	(32.1)	2.4	9.5	(7.0)	(0.1)	(453.6)	1.1	(452.5)	(439.2)
25	Meters (478)	(616.8)	(107.1)	36.9	(0.5)	0.5	-	(687.0)	-	(687.0)	(650.5)
26	Sub-Total	(6,253.7)	(559.2)	92.2	91.3	(13.2)	(9.5)	(6,652.1)	3.6	(6,648.5)	(6,452.5)
	General Plant - EGI										
27	Investment in leased assets (101)	(1.4)	-	-	-	-	(0.6)	(2.0)	-	(2.0)	(1.7)
28	Structures & improvements (482)	(73.0)	(13.1)	3.9	-	-	(0.2)	(82.4)	0.2	(82.2)	(78.1)
29	Office furniture and equipment (483)	(23.5)	(1.3)	1.4	-	-	-	(23.5)	-	(23.5)	(23.5)
30	Transportation equipment (484)	(117.9)	(5.5)	6.1	(0.7)	0.8	-	(117.3)	0.1	(117.2)	(118.2)
31	NGV conversion kits (484)	(0.5)	(0.1)	-	-	-	-	(0.7)	-	(0.7)	(0.6)
32	Heavy work equipment (485)	(20.6)	(3.4)	0.6	(0.2)	0.2	-	(23.4)	-	(23.4)	(22.1)
33	Tools and work equipment (486)	(12.6)	(7.6)	0.2	0.0	(0.0)	-	(20.0)	-	(20.0)	(16.4)
34	Rental equipment (487)	(0.2)	(0.1)	-	-	-	-	(0.3)	-	(0.3)	(0.3)
35	NGV rental compressors (487)	(4.3)	(0.4)	-	-	-	-	(4.7)	-	(4.7)	(4.4)
36	NGV cylinders (484 and 487)	(0.6)	(0.0)	-	-	-	-	(0.6)	-	(0.6)	(0.6)
37	Communication equipment (488)	2.4	(0.5)	-	-	-	-	1.8	-	1.8	2.1
38	Computer equipment (490)	(16.9)	(5.1)	8.8	-	-	-	(13.2)	-	(13.2)	(15.4)
39	Software Aquired/Developed (491) (1)	(71.3)	(18.1)	24.0	-	-	2.3	(63.1)	-	(63.1)	(68.1)
40	WAMS (489)	(57.1)	(9.1)	-	-	-	-	(66.3)	-	(66.3)	(61.7)
41	Sub-Total	(397.5)	(64.4)	44.9	(0.9)	0.9	1.5	(415.6)	0.3	(415.3)	(408.9)
	Local Storage Plant - EGI										
42	Structures and improvements (442)	(3.2)	(0.1)	-	0.0	(0.0)	(0.0)	(3.3)	-	(3.3)	(3.2)
43	Gas holders - storage (443)	(4.4)	(0.1)	-	-	-	(0.0)	(4.4)	-	(4.4)	(4.4)
44	Gas holders - equipment (443)	(13.1)	(0.3)	-	-	-	0.0	(13.4)	-	(13.4)	(13.3)
45	Sub-Total	(20.6)	(0.5)	-	0.0	(0.0)	(0.0)	(21.2)	-	(21.2)	(20.9)
	Intangible Plant - EGI										
46	Inactive services (102)	(1.6)	(0.0)	-	-	-	-	(1.6)	-	(1.6)	(1.6)
47	Franchises and consents (401)	(1.2)	(0.1)	-	-	-	-	(1.2)	-	(1.2)	(1.2)
48	Other intangible plant (402)	(0.5)	-	-	-	-	-	(0.5)	-	(0.5)	(0.5)
49	Sub-Total	(3.3)	(0.1)	-	-	-	-	(3.4)	-	(3.4)	(3.3)
50	EGI Total	(9,039.1)	(765.4)	129.9	97.4	(4.5)	1.5	(9,580.2)	4.2	(9,575.9)	(9,311.2)

Notes:
(1) Opening balance and current year amortization have been updated to reflect adjustments related to depreciation error impacting 2024 & 2025.

EGI Working Capital Components
Month End Balances and Average of Monthly Averages
2025 Actual

Line No.	Particulars ($ millions)	Col. 1 Materials and Supplies	Col. 2 ABC Receivable	Col. 3 Customer Security Deposits	Col. 4 Gas in Storage	Col. 5 Working Cash Allowance	Col. 6 Total
1	January 1	142.5	(16.8)	(65.0)	644.0	(31.3)	673.5
2	January 31	144.2	(10.3)	(63.3)	540.1	(31.3)	579.4
3	February	145.0	(22.1)	(63.1)	453.8	(31.3)	482.2
4	March	146.5	(46.0)	(64.2)	361.4	(31.3)	366.3
5	April	153.7	(38.9)	(63.7)	411.1	(31.3)	430.9
6	May	152.7	(35.3)	(64.1)	465.0	(31.3)	486.9
7	June	153.5	(45.5)	(64.5)	569.1	(31.3)	581.3
8	July	156.0	(21.1)	(63.9)	686.4	(31.3)	726.2
9	August	156.0	(11.0)	(64.7)	794.8	(31.3)	843.8
10	September	157.7	(14.8)	(67.4)	887.6	(31.3)	931.8
11	October	157.0	(0.1)	(66.5)	886.3	(31.3)	945.4
12	November	159.1	(2.0)	(63.5)	775.9	(31.3)	838.2
13	December	155.4	(22.9)	(61.3)	683.0	(31.3)	722.9
14	Avg. of monthly avgs.	152.5	(22.2)	(64.3)	624.6	(31.3)	659.2

EGI Summary of Capital Structure & Cost of Capital
2025 Actual

Line No.	Particulars	Col. 1 Utility Capital Structure Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component	Col. 5 (Col. 1x Col. 3 Interest & Return
		($Millions)	%	%	%	($Millions)
1	Long and Medium-Term Debt	9,867.5	59.10	4.16	2.460	410.8
2	Short-Term Debt	484.9	2.90	2.89	0.084	14.0
3	Total Debt	10,352.4	62.00		2.544	424.8
4	Preference Shares	-	-	-	-	-
5	Common Equity	6,345.0	38.00	10.21	3.880	647.8
6	Total Rate Base	16,697.4	100.00		6.424	1,072.7

Calculation of Cost Rates
For EGI Capital Structure Components
2025 Actual

Line No.	Particulars		Col. 1 Average of Monthly Averages ($Millions)	Col. 2	Col. 3 Carrying Cost ($Millions)
	Long and Medium-Term Debt				
1	Debt Summary		10,133.5		425.8
2	Unamortized Finance Costs		94.0		-
3	(Profit)/Loss on Redemption		-		-
4			10,227.5		425.8
5	Percentage Allocation of Debt to Unregu	3.52%	(360.0)		(15.0)
6	Net Regulated Long and Medium-Term Debt		9,867.5		410.8
7	Calculated Cost Rate			4.16%	
	Short-Term Debt				
8	Calculated Cost Rate			2.89%	
	Common Equity				
9	Board Formula ROE			9.21%	
10	Threshold before earnings sharing			1.00%	

EGI Summary Statement of Principal
and Carrying Costs of
Term Debt
2025 Actual

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Average Principal	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost
			($Millions)		($Millions)
Medium Term Notes					
1	4.20%	June 2, 2044	250.0	4.24%	10.6
2	4.20%	June 2, 2044	250.0	4.27%	10.7
3	6.05%	September 2, 2038	300.0	6.10%	18.3
4	4.88%	June 21, 2041	300.0	4.92%	14.8
5	5.20%	July 23, 2040	250.0	5.27%	13.2
6	2.81%	June 1, 2026	250.0	2.87%	7.2
7	3.80%	June 1, 2046	250.0	3.84%	9.6
8	2.88%	November 22, 2027	250.0	2.95%	7.4
9	3.59%	November 22, 2047	250.0	3.64%	9.1
10	3.19%	September 17, 2025	141.7	3.26%	4.6
11	5.46%	September 11, 2036	165.0	5.49%	9.1
12	8.65%	November 10, 2025	109.4	8.77%	9.6
13	8.85%	October 2, 2025	15.8	8.97%	1.4
14	7.60%	October 29, 2026	100.0	8.09%	8.1
15	6.65%	November 3, 2027	100.0	6.71%	6.7
16	6.10%	May 19, 2028	100.0	6.16%	6.2
17	6.90%	November 15, 2032	150.0	6.95%	10.4
18	6.16%	December 16, 2033	150.0	6.18%	9.3
19	5.21%	February 25, 2036	300.0	5.18%	15.5
20	4.95%	November 22, 2050	200.0	4.99%	10.0
21	4.95%	November 22, 2050	100.0	4.73%	4.7
22	4.50%	November 23, 2043	200.0	4.20%	8.4
23	4.00%	August 22, 2044	215.0	3.89%	8.4
24	4.00%	August 22, 2044	170.0	4.44%	7.5
25	3.31%	September 11, 2025	283.3	3.62%	10.3
26	2.50%	August 5, 2026	300.0	3.42%	10.3
27	3.51%	November 29, 2047	300.0	3.53%	10.6
28	2.37%	August 9, 2029	400.0	3.23%	12.9
29	3.01%	August 9, 2049	300.0	3.03%	9.1
30	2.90%	April 1, 2030	600.0	3.41%	20.4
31	3.65%	April 1, 2050	600.0	3.67%	22.0
32	2.35%	September 1, 2031	475.0	2.94%	14.0
33	3.20%	September 1, 2051	425.0	3.22%	13.7
34	4.15%	August 17, 2032	325.0	3.15%	10.2
35	4.55%	August 17, 2052	325.0	4.52%	14.7
36	5.46%	October 6, 2028	250.0	5.54%	13.9
37	5.70%	October 6, 2033	400.0	3.70%	14.8
38	5.67%	October 6, 2053	350.0	5.08%	17.8
39	4.16%	September 12, 2035	145.8	4.16%	6.1
40	4.84%	September 12, 2055	87.5	4.83%	4.2
41	Total Term Debt		10,133.5		425.8

EGI Unamortized Debt Discount and Expense
Average of Monthly Averages
2025 Actual

Line No.	Particulars	Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	(95.1)
2.	January 31	(93.5)
3.	February	(93.5)
4.	March	(93.5)
5.	April	(93.5)
6.	May	(93.5)
7.	June	(93.5)
8.	July	(93.5)
9.	August	(93.5)
10.	September	(95.5)
11.	October	(95.0)
12.	November	(94.9)
13.	December	(94.8)
14.	Average of Monthly Averages	(94.0)

Reconciliation of Audited EGI Income (Per Financial Statements)
To Corporate Income for Utility Income Determination Purposes
2025 Actual

Line No.	Parituclars ($ millions)	Col. 1 Audited Income (as per Financial Statements)	Col. 2 Corporate Income (as per Utility Income Schedule)	Col. 3 Variance	Col. 4 Reference
	Operating Revenues				
1.	Gas sales and distribution	5,545.5	5,546.4		
2.	Storage, transportation and other	567.0	-		
3.	Transportation	-	169.7		
4.	Storage	-	326.8		
5.	Other operating revenue	-	69.7		
6.	Other Income	102.0	13.8		
7.	Total operating revenue	6,214.5	6,126.3	(88.2)	(a)
	Operating Expenses				
8.	Gas Costs	2,660.7	2,660.7	-	
9.	Operation and maintenance	1,317.1	1,089.3	(227.8)	(b)
10.	Depreciation and amortization expense	808.2	808.2	-	
11.	Impairment of long-lived assets	-	-	-	
12.	Fixed financing costs	-	2.2	2.2	(c)
13.	Municipal and other taxes	-	139.2	139.2	(d)
14.	Cost of service	4,786.0	4,699.6	(86.4)	
15.	Income before interest and income taxes	1,428.5	1,426.7	(1.8)	
16.	Interest and financing expenses	448.1	-	(448.1)	(e)
17.	Income before income taxes	980.4	1,426.7	446.3	
18.	Income taxes	190.9	-	(190.9)	(f)
19.	Net Income	789.5	1,426.7	637.2	

Col. 2 - Corporate income as reported in Exhibit B, Tab 1, Schedule 3, Column 1

a)	Audited Total Operating Revenue	6,214.5
	Reclassify pension related other revenue to O&M	(89.0)
	Reclassify other expenses out of other income to O&M	0.4
	Reclassify bank interest to interest and financing expenses	0.3
	Rounding	0.1
	Corporate Total Operating Revenue	6,126.3
b)	Audited Operation and Maintenance	1,317.1
	Reclassify pension related other revenue to O&M	(89.0)
	Reclassify Municipal & Property Taxes out of O&M	(139.2)
	Reclassify other expenses out of other income to O&M	0.4
	Corporate Operation and Maintenance	1,089.3
c)	Audited Fixed Financing Costs	-
	Reclassify fixed financing costs from interest and financing expenses	2.2
	Corporate Fixed Financing Costs	2.2
d)	Audited Municipal and Other Taxes	-
	Reclassify Municipal and other taxes included within O&M costs	139.2
	Corporate Municipal and Other Taxes	139.2
e)	Audited Interest and Financing expenses	448.1
	Reclassify fixed financing costs from interest and financing expenses	(2.2)
	Reclassify bank interest from other revenue	0.3
	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure	(446.2)
	Corporate Interest and Financing expenses	-
f)	Audited Income Taxes	190.9
	Elimination of corporate income taxes which will be calculated on a utility stand-alone basis	(190.9)
	Corporate Income Taxes	-

Average Customers by Rate Class

Line No.	Particulars	2024 Actual			2025 Actual			Variance
		Sales Service	Direct Purchase	Total	Sales Service	Direct Purchase	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	2,135,254	25,993	2,161,247	2,155,832	23,636	2,179,468	18,221
2	Rate 6	147,679	23,796	171,475	150,212	23,834	174,046	2,571
3	Rate M1	1,175,355	27,897	1,203,251	1,185,658	26,822	1,212,479	9,228
4	Rate M2	5,294	3,854	9,148	5,585	3,884	9,469	320
5	Rate 01	360,504	10,043	370,547	363,227	9,652	372,879	2,332
6	Rate 10	1,550	1,001	2,551	1,555	1,007	2,562	11
7	Total General Service	3,825,635	92,584	3,918,219	3,862,068	88,834	3,950,903	32,683
	Contract							
8	Rate 100 (1)	6	15	21	7	14	21	(0)
9	Rate 110	76	398	473	83	411	494	20
10	Rate 115	0	17	17	0	16	16	(0)
11	Rate 125	0	4	4	0	4	4	0
12	Rate 135	3	40	43	4	40	45	2
13	Rate 145	1	14	15	1	14	15	(1)
14	Rate 170	0	20	20	0	20	20	(0)
15	Rate 200	1	0	1	1	0	1	0
16	Rate 300	0	0	0	0	0	0	0
17	Rate 315	0	0	0	0	0	0	0
18	Rate M4	25	196	221	34	190	224	3
19	Rate M5	11	30	42	13	29	42	0
20	Rate M7	2	68	70	3	73	77	6
21	Rate M9	1	3	4	1	3	4	0
22	Rate M10	1	0	1	0	0	0	(1)
23	Rate T1	0	37	37	0	39	39	2
24	Rate T2	0	27	27	0	26	26	(1)
25	Rate T3	0	1	1	0	1	1	0
26	Rate 20	5	60	65	5	62	67	2
27	Rate 25	27	17	43	51	55	105	62
28	Rate 30	0	0	0	0	0	0	0
29	Rate 100 (2)	0	11	11	0	9	9	(2)
30	Total Contract	159	957	1,117	202	1,005	1,207	91
31	Total Customers	3,825,794	93,542	3,919,336	3,862,270	89,840	3,952,110	32,774

Notes:
(1) EGD rate zone.
(2) Union North rate zone.

Throughput Volumes by Rate Class - Unnormalized

Line No.	Particulars (10^3m^3)	2024 Actual			2025 Actual			Variance
		Sales Service	Direct Purchase	Total	Sales Service	Direct Purchase	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	4,477,473	55,056	4,532,530	5,099,073	55,155	5,154,228	621,698
2	Rate 6	2,718,250	1,572,775	4,291,025	3,114,069	1,901,420	5,015,489	724,464
3	Rate M1	2,627,154	170,856	2,798,010	2,983,202	193,089	3,176,291	378,281
4	Rate M2	513,278	647,292	1,160,571	573,858	732,856	1,306,713	146,143
5	Rate 01	815,213	65,762	880,975	932,236	70,914	1,003,149	122,174
6	Rate 10	143,178	155,935	299,113	144,631	172,254	316,885	17,772
7	Total General Service	11,294,546	2,667,676	13,962,223	12,847,068	3,125,687	15,972,755	2,010,532
	Contract							
8	Rate 100 (1)	12,559	30,885	43,443	14,549	45,444	59,993	16,549
9	Rate 110	122,632	1,155,035	1,277,667	138,130	1,181,493	1,319,623	41,956
10	Rate 115	-	341,507	341,507	0	335,399	335,399	(6,108)
11	Rate 125	-	1,377,941	1,377,941	-	1,618,789	1,618,789	240,848
12	Rate 135	2,442	67,048	69,489	1,627	59,437	61,064	(8,425)
13	Rate 145	513	59,957	60,470	413	59,504	59,917	(553)
14	Rate 170	-	241,282	241,282	-	314,998	314,998	73,716
15	Rate 200	119,874	62,669	182,543	145,524	65,696	211,220	28,677
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	44,275	519,084	563,359	53,253	528,895	582,148	18,789
19	Rate M5	1,684	50,373	52,057	4,148	50,095	54,243	2,186
20	Rate M7	7,460	764,336	771,796	11,458	910,698	922,157	150,360
21	Rate M9	15,819	80,879	96,697	19,774	86,473	106,247	9,550
22	Rate M10	247	-	247	-	-	-	(247)
23	Rate T1	-	403,660	403,660	-	415,028	415,028	11,368
24	Rate T2	-	5,491,895	5,491,895	-	5,926,779	5,926,779	434,885
25	Rate T3	-	249,479	249,479	-	282,401	282,401	32,922
26	Rate 20	6,816	1,230,189	1,237,005	8,810	1,496,712	1,505,522	268,516
27	Rate 25	70,214	222,815	293,029	157,836	194,358	352,194	59,166
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (2)	-	944,814	944,814	-	864,327	864,327	(80,487)
30	Total Contract	404,534	13,293,848	13,698,382	555,522	14,436,528	14,992,050	1,293,668
31	Total Throughput Volum	11,699,080	15,961,525	27,660,605	13,402,590	17,562,216	30,964,805	3,304,200

Notes:
(1) EGD rate zone.
(2) Union North rate zone.

Throughput Volumes by Rate Class - Normalized

Line No.	Particulars (10^3m^3)	2024 Actual			2025 Actual			Variance
		Sales Service	Direct Purchase	Total	Sales Service	Direct Purchase	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	5,010,075	61,795	5,071,871	4,855,164	52,580	4,907,744	(164,126)
2	Rate 6	2,989,982	1,743,179	4,733,161	2,992,308	1,831,663	4,823,971	90,810
3	Rate M1	2,956,058	194,443	3,150,501	2,887,822	187,111	3,074,933	(75,567)
4	Rate M2	571,616	726,100	1,297,716	553,913	717,263	1,271,176	(26,540)
5	Rate 01	919,537	73,391	992,927	907,209	69,069	976,278	(16,649)
6	Rate 10	159,083	172,926	332,009	141,210	168,025	309,235	(22,774)
7	Total General Service	12,606,350	2,971,834	15,578,184	12,337,627	3,025,711	15,363,338	(214,847)
	Contract							
8	Rate 100 (1)	12,559	30,885	43,443	14,549	45,444	59,993	16,549
9	Rate 110	122,632	1,155,035	1,277,667	138,130	1,181,493	1,319,623	41,956
10	Rate 115	-	341,507	341,507	0	335,399	335,399	(6,108)
11	Rate 125	-	1,377,941	1,377,941	-	1,618,789	1,618,789	240,848
12	Rate 135	2,442	67,048	69,489	1,627	59,437	61,064	(8,425)
13	Rate 145	513	59,957	60,470	413	59,504	59,917	(553)
14	Rate 170	-	241,282	241,282	-	314,998	314,998	73,716
15	Rate 200	119,874	62,669	182,543	145,524	65,696	211,220	28,677
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	44,275	519,084	563,359	53,253	528,895	582,148	18,789
19	Rate M5	1,684	50,373	52,057	4,148	50,095	54,243	2,186
20	Rate M7	7,460	764,336	771,796	11,458	910,698	922,157	150,360
21	Rate M9	15,819	80,879	96,697	19,774	86,473	106,247	9,550
22	Rate M10	247	-	247	-	-	-	(247)
23	Rate T1	-	403,660	403,660	-	415,028	415,028	11,368
24	Rate T2	-	5,491,895	5,491,895	-	5,926,779	5,926,779	434,885
25	Rate T3	-	249,479	249,479	-	282,401	282,401	32,922
26	Rate 20	6,816	1,230,189	1,237,005	8,810	1,496,712	1,505,522	268,516
27	Rate 25	70,214	222,815	293,029	157,836	194,358	352,194	59,166
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (2)	-	944,814	944,814	-	864,327	864,327	(80,487)
30	Total Contract	404,534	13,293,848	13,698,382	555,522	14,436,528	14,992,050	1,293,668
31	Total Throughput Volum	13,010,884	16,265,683	29,276,566	12,893,149	17,462,239	30,355,388	1,078,822

Notes:
(1) EGD rate zone.
(2) Union North rate zone.

Revenue by Rate Class - Unnormalized

Line No.	Particulars ($ millions)	2024 Actual			2025 Actual			Variance
		Sales Service	Direct Purchase	Total	Sales Service	Direct Purchase	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	1,803.4	14.3	1,817.6	2,116.4	14.6	2,131.0	313.4
2	Rate 6	783.0	152.5	935.5	940.8	199.3	1,140.1	204.6
3	Rate M1	904.2	19.3	923.5	1,089.0	21.7	1,110.6	187.1
4	Rate M2	109.6	44.4	154.0	143.5	57.0	200.5	46.5
5	Rate 01	365.9	14.7	380.6	427.8	15.8	443.5	63.0
6	Rate 10	39.7	20.9	60.7	45.0	25.2	70.2	9.5
7	Total General Service	4,005.8	266.0	4,271.9	4,762.4	333.6	5,096.0	824.1
	Contract							
8	Rate 100 (2)	3.4	3.1	6.5	4.3	4.3	8.6	2.1
9	Rate 110	23.9	50.3	74.2	29.7	55.3	85.0	10.8
10	Rate 115	0.0	8.3	8.3	(0.0)	8.9	8.9	0.6
11	Rate 125	-	13.4	13.4	-	15.0	15.0	1.6
12	Rate 135	0.5	2.9	3.4	0.4	2.5	2.9	(0.5)
13	Rate 145	0.1	2.2	2.3	0.1	3.2	3.3	1.0
14	Rate 170	(0.4)	2.0	1.6	(0.0)	4.1	4.1	2.5
15	Rate 200	23.2	3.1	26.3	29.7	3.8	33.4	7.1
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	9.5	32.8	42.3	13.9	34.1	48.0	5.8
19	Rate M5	0.5	2.1	2.6	1.2	2.7	3.9	1.2
20	Rate M7	1.8	31.1	32.9	3.4	35.9	39.3	6.3
21	Rate M9	2.9	1.3	4.2	3.9	1.5	5.4	1.2
22	Rate M10	0.1	-	0.1	-	-	-	(0.1)
23	Rate T1	-	13.3	13.3	-	15.1	15.1	1.8
24	Rate T2	-	87.7	87.7	-	92.5	92.5	4.8
25	Rate T3	-	7.8	7.8	-	8.2	8.2	0.4
26	Rate 20	2.7	38.8	41.5	3.1	44.5	47.5	6.1
27	Rate 25	12.6	8.3	21.0	33.5	8.6	42.1	21.1
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (3)	-	11.3	11.3	-	11.1	11.1	(0.2)
30	Total Contract	80.9	319.9	400.8	123.2	351.1	474.3	73.5
31	Subtotal	4,086.7	585.9	4,672.7	4,885.6	684.7	5,570.3	897.6
32	Other Adjustments (3)			31.9			(37.5)	(69.4)
33	Total Gas Sales and Distribution Revenue			4,704.5			5,532.8	828.2
	Utility Adjustments							
34	Elimination of the 2025 ESM and Union rate zones' unregulated storage cost from the EGD rate zone revenues			(18.6)			10.6	29.2
35	Total Utility Revenue			4,686.0			5,543.4	857.4

Notes:
(1) EGD rate zone.
(2) Union North rate zone.
(3) Includes adjustments that either do not have rate class detail or are not allocated between System and DP customers.

Revenue by Rate Class - Normalized

Line No.	Particulars ($ millions)	2024 Actual			2025 Actual			Variance
		Sales Service	Direct Purchase	Total	Sales Service	Direct Purchase	Total	
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-c)
	General Service							
1	Rate 1	1,947.2	15.0	1,962.2	2,053.0	14.3	2,067.3	105.1
2	Rate 6	849.4	166.3	1,015.7	912.6	193.3	1,105.9	90.2
3	Rate M1	975.7	20.7	996.4	1,069.5	21.3	1,090.8	94.3
4	Rate M2	122.2	49.4	171.7	139.4	55.9	195.3	23.6
5	Rate 01	399.6	16.0	415.6	420.1	15.4	435.5	19.9
6	Rate 10	44.1	23.1	67.2	44.0	24.6	68.7	1.5
7	Total General Service	4,338.2	290.6	4,628.8	4,638.5	324.8	4,963.4	334.6
	Contract							
8	Rate 100 (1)	3.4	3.1	6.5	4.3	4.3	8.6	2.1
9	Rate 110	23.9	50.3	74.2	29.7	55.3	85.0	10.8
10	Rate 115	0.0	8.3	8.3	(0.0)	8.9	8.9	0.6
11	Rate 125	-	13.4	13.4	-	15.0	15.0	1.6
12	Rate 135	0.5	2.9	3.4	0.4	2.5	2.9	(0.5)
13	Rate 145	0.1	2.2	2.3	0.1	3.2	3.3	1.0
14	Rate 170	(0.4)	2.0	1.6	(0.0)	4.1	4.1	2.5
15	Rate 200	23.2	3.1	26.3	29.7	3.8	33.4	7.1
16	Rate 300	-	-	-	-	-	-	-
17	Rate 315	-	-	-	-	-	-	-
18	Rate M4	9.5	32.8	42.3	13.9	34.1	48.0	5.8
19	Rate M5	0.5	2.1	2.6	1.2	2.7	3.9	1.2
20	Rate M7	1.8	31.1	32.9	3.4	35.9	39.3	6.3
21	Rate M9	2.9	1.3	4.2	3.9	1.5	5.4	1.2
22	Rate M10	0.1	-	0.1	-	-	-	(0.1)
23	Rate T1	-	13.3	13.3	-	15.1	15.1	1.8
24	Rate T2	-	87.7	87.7	-	92.5	92.5	4.8
25	Rate T3	-	7.8	7.8	-	8.2	8.2	0.4
26	Rate 20	2.7	38.8	41.5	3.1	44.5	47.5	6.1
27	Rate 25	12.6	8.3	21.0	33.5	8.6	42.1	21.1
28	Rate 30	-	-	-	-	-	-	-
29	Rate 100 (2)	-	11.3	11.3	-	11.1	11.1	(0.2)
30	Total Contract	80.9	319.9	400.8	123.2	351.1	474.3	73.5
31	Subtotal	4,419.1	610.5	5,029.6	4,761.7	675.9	5,437.6	408.1
32	Other Adjustments (3)			31.9			(37.5)	(69.4)
33	Total Gas Sales and Distribution Revenue			5,061.5			5,400.1	338.7
	Utility Adjustments							
34	Elimination of the 2025 ESM and Union rate zones' unregulated storage cost from the EGD rate zone revenues			(18.6)			10.6	29.2
35	Total Utility Revenue			5,042.9			5,410.7	367.8

Notes:
(1) EGD rate zone.
(2) Union North rate zone.
(3) Includes adjustments that either do not have rate class detail or are not allocated between System and DP customers.

Revenue from Regulated Storage & Transportation

Line No.	Particulars ($ millions)	2024 Actual (a)	2025 Actual (b)	Variance (c) = (b-a)
	Storage			
1	Peak Storage	0.9	0.2	(0.7)
2	Off-peak Storage	2.4	0.0	(2.4)
3	Loans	(0.0)	0.0	0.0
4	Short-term Balancing	2.0	0.4	(1.6)
5	Short-term Deferral	(4.9)	(0.6)	4.3
6	Total Storage	0.4	0.0	(0.4)
	Utility Adjustment			
7	Elimination of the shareholder portion of net Short-term Storage Revenue	(0.4)	(0.1)	0.3
8	Total Storage - Utility Revenue	(0.0)	(0.0)	(0.0)
	Transportation			
9	Rate M12	94.0	95.6	1.6
10	Rate M12X	3.2	3.4	0.2
11	Rate F24T	0.6	0.7	0.1
12	Rate C1	18.7	19.6	0.9
13	Rate M13	0.5	2.1	1.6
14	Rate M16	0.6	0.7	0.1
15	Rate M17	0.5	0.6	0.0
16	Rate 331	0.2	0.2	0.0
17	Rate 332	20.0	21.9	1.9
18	Rate 401	1.5	1.7	0.1
19	Short-term Transportation	11.7	17.1	5.4
20	Upstream Transportation Optimization	5.9	6.1	0.2
21	Other	1.2	1.2	(0.0)
22	Total Transportation	158.7	170.9	12.2
	Utility Adjustment			
23	Elimination of the shareholder portion of net Upstream Optimization	(5.4)	(5.6)	(0.2)
24	Total Transportation - Utility Revenue	153.3	165.3	12.0
25	Total Storage & Transportation - Utility Revenue	153.3	165.3	12.0

Other Revenue and Other Income

Line No.	Particulars ($ millions)	2024 Actual (a)	2025 Actual (b)	Variance (c) = (b-a)
	Other Revenue			
1	Late Payment Penalties	21.9	22.7	0.8
2	Account Opening Charges	9.0	9.3	0.4
3	Other Billing Revenue	11.8	11.9	0.1
4	Customer Billing Revenue	42.7	44.0	1.3
5	Direct Purchase Administration Charges and Distributor Consolidated Billing	4.5	5.4	0.9
6	Open Bill Access Revenue	9.6	(0.0)	(9.6)
7	Rental Revenue - NGV Program	1.8	1.9	0.1
8	Other Operating Revenue	16.7	11.2	(5.5)
9	Subtotal	75.3	62.5	(12.8)
	Utility Adjustments			
10	Elimination of demand-side management incentive	(12.4)	(10.8)	1.6
11	Total Other Revenue	62.9	51.8	(11.2)
	Other Income			
12	Other Income (1)	6.1	13.9	7.8
	Utility Adjustments			
13	Elimination of interest income from investments not included in utility rate base and the portion of gains on sale of assets not shared through deferral	(0.6)	(8.8)	(8.2)
14	Total Other Income	5.4	5.1	(0.4)

Note:
(1) Includes the portion of gains on sale of assets not shared through deferral, interest income from investments not included in utility rate base, gains/losses on FX, and sales-type lease lease income related to the NGV Program.

UTILITY OPERATING AND MAINTENANCE

1. This evidence explains the drivers of the change in Utility Operating and Maintenance (O&M) expense from 2024 actual to 2025 actual.

2. Table 1 presents 2025 O&M expenses relative to 2024 O&M expenses.

3. Overall, Utility O&M expenses decreased by $44.8 million between 2024 and 2025, primarily due to the discontinuation of one-time severance costs incurred in 2024 and lower pension-related costs incurred in 2025 as compared to 2024. These decreases were partially offset by higher Energy Conservation program costs, higher professional services costs, and lower indirect overhead recoveries.

Table 1
Utility O&M
25 Actuals-24 Actuals

Line No.	Expense Categories	2024 OEB-Approved	2024 Actual ($ millions)	2025 Actual ($ millions)	2025 Actual vs 2024 Actual $ change	2025 Actual vs 2024 Actual % change
1	Compensation & Benefits	416.5	446.3	340.9	(105.4)	-23.6%
2	Outside Services	262.4	246.6	250.0	3.5	1.4%
3	Materials and Supplies	31.2	29.5	32.2	2.7	9.1%
4	Professional and Regulatory Services	18.0	26.3	43.3	17.0	64.5%
5	Other	59.0	55.8	69.7	13.9	24.9%
6	Employee Related Services	4.8	1.2	2.3	1.1	95.2%
7	Repairs & Maintenance	4.4	5.6	6.5	0.9	16.3%
8	Rents & Leases	13.1	13.2	12.7	(0.5)	-3.6%
9	Travel & Accommodation	9.1	8.7	10.9	2.2	25.3%
10	Donations & Memberships	5.1	6.2	1.1	(5.1)	-82.7%
11	Internal Allocation & Recoveries	(20.7)	(24.5)	(63.1)	(38.7)	-58.1%
12	Energy Conservation	183.1	183.1	195.1	12.0	6.6%
13	Central Functions	377.1	348.2	352.6	4.4	1.3%
14	Overhead Capitalization	(242.0)	(242.0)	(192.0)	50.0	-20.7%
15	O&M settlement reduction - ($50M net, $68M gross)	(68.4)				0.0%
16	O&M Subtotal before adjustments	1,052.8	1,104.2	1,062.3	(41.9)	-4.0%
17	Donations		(2.9)	(3.1)	(0.2)	6.0%
18	2025 DSMVA Correction			0.9	0.9	
19	Less write down of locates for 2023			(3.0)	(3.0)	
20	CF utility adjustment		(8.5)	(9.1)	(0.5)	6.4%
21	Total Unregulated/Non-Utility Eliminations		(11.5)	(14.3)	(2.9)	25%
22	Total Net Utility O&M Expense	1,052.8	1,092.8	1048.0	(44.8)	-4.3%

4. 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, reflecting strong pension asset performance and lower expense requirements following interest rate cuts. Pension expense remains a deferrable amount addressed in the Post Retirement True-up variance account.

5. 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 flow-through costs, fully recoverable through Internal Allocations and Recoveries (line 11). These increases were partially offset by approximately $3.0 million of favorability related to OEB assessment costs.

6. Other (line 5) increased by approximately $15 million, primarily reflecting incremental labor costs for work performed for affiliates captured through time sheeting, which are recovered through Internal Allocations and Recoveries.

7. Internal Allocations and Recoveries (line 11) increased by $38.7 million, driven by higher recoveries from affiliates.

8. DSM (line 12) increased by $12.0 million, representing the OEB-approved year-over-year budget increase. DSM amounts above the OEB-approved budget remain a pass-through component of Utility O&M and are fully recoverable through the DSM variance account.

9. Overhead Capitalization (line 14) decreased by approximately $50 million, consistent with the OEB's 2024 Rebasing Phase 1[1] rate order, which mandates an annual $50 million reduction from the $242 million approved in 2024.

[1] EB-2022-0200.

UTILITY CAPITAL EXPENDITURES

1. This evidence provides information on Enbridge Gas's 2025 utility capital expenditures.

Table 1
Summary of Capital Expenditures 2025 Actual

Line No.	Particulars ($ millions)	Total EGI
1	Distribution Plant	840.4
2	Transmission Plant (1)	134.6
3	General & Other Plant	147.0
4	Underground Storage Plant	46.2
5	Total	1,168.2

Note:
(1) Includes PREP amounts of $8.7 million subject to levelized ratemaking treatment.

The amounts presented reflect annual capital expenditures and are comparable to the Asset Management Plan.

2. Enbridge Gas's 2025 total capital expenditure is broadly consistent with 2024 and remains aligned with the OEB's 2024 Rebasing Phase 1 Decision[1]. Through the Distribution Integrity Management Program (DIMP) and the Enhanced Distribution Integrity Management Program (EDIMP)[2] activities, Enbridge Gas has extended asset life through targeted inspection and repair, supporting prudent prioritization of capital spending in 2025. As discussed in the Phase 3 Report on Capital Reduction[3], while near-term pacing actions were implemented to achieve the 2024 capital reduction, the underlying system requirements remain. As a result, certain projects deferred in 2024 began execution in 2025, with higher capital demands expected in 2026 and beyond.

[1] EB-2022-0200, OEB Decision and Order, December 21, 2023.
[2] Exhibit G, Tab 4, Schedule 1.
[3] EB-2025-0064, Exhibit 2, Tab 5, Schedule 5.

3. Table 2 presents year-over-year (2024–2025) capital expenditure variances by asset class, with supporting commentary provided in the narrative that follows.

Table 2
Asset Class

Line No.	Asset Class ($ millions)	2024	2025	Variance
1	Compression Stations	41.5	40.7	(0.8)
2	Customer Connections	282.7	241.7	(41.0)
3	Distribution Pipe	215.4	326.2	110.9
4	Distribution Stations	25.9	58.6	32.7
5	Fleet & Equipment	19.2	37.1	17.9
6	Growth - Distribution System Reinforcement	18.8	24.2	5.4
7	Real Estate & Workplace Services	69.4	37.3	(32.1)
8	Technology Information Services (TIS)	43.4	77.7	34.3
9	Transmission Pipe and Underground Storage	228.8	113.9	(114.9)
10	Utilization	189.6	163.0	(26.5)
11	EA Fixed Overhead	39.8	37.7	(2.1)
12	Community Expansion	8.3	8.8	0.5
13	Other	17.0	1.3	(15.7)
14	Total	1,199.8	1,168.2	(31.6)

1. Descriptions of Asset Classes and Year-over-Year Variances

a) Compression Stations

- Enbridge Gas uses compressors to move natural gas throughout the natural gas transmission system by compressing natural gas into transmission pipelines designed for high pressure and flow. Compressors are also used to move gas in and out of underground storage reservoirs by providing a significant pressure increase at the expense of flow.
- Dehydration facilities are also included in the compression asset category. Dehydration facilities remove moisture from natural gas to ensure that the natural gas entering the transmission system meets the contractual standard of moisture content, and to avoid operational problems related to high moisture content. Enbridge Gas operates one liquified natural gas

(LNG) facility. The LNG facility serves to provide reserve capacity and balance operational loads during peak periods.

- Compression Stations decreased by $0.8 million which was primarily driven by timing. Dawn to Corunna spend was finished in 2024 causing a decrease of $23.7 million which was offset by increases to Condition Based Replacements $7.0 million which was driven by previously deferred projects, $6.5 million driven by opportunistic purchases of required land, Emissions Reductions Program $3.4 million and Overhauls Program $3.8 million, which included the advance procurement to support the planned 2026 Dawn D RB211 C-to-G conversion $3.7 million.

b) Customer Connections

- This asset class includes the addition of new customers based on new housing or business starts, customers converting to natural gas from another fuel source and equipment and service upgrades to accommodate load growth of existing customers. General customer growth costs include materials and installation of mains and services to attach new customers as well as the costs associated with the meter and regulator installation at the customers site.
- Customer Connections capital decreased by ($41.0 million) in 2025 compared to 2024. This reduction is primarily attributable to fewer customer additions in 2025, consistent with lower housing starts and slower activity in the new construction market. In 2025, customer additions were approximately 18% lower than in 2024, resulting in lower associated main, service, meter, and regulator installation costs.

c) Distribution Pipe

- This asset class includes the capital maintenance, replacement, enhancement and renewal of pipelines and piping components (such as

valves and fittings) used to transport natural gas within the distribution system or to end-use customers. It includes steel and plastic pipe, as well as services to customers.

- Distribution Pipe capital increased by $110.9 million in 2025 compared to 2024, primarily reflecting the execution of previously deferred work and the timing of large, planned projects, consistent with the Phase 3 Report on Capital Reduction[4] and the Asset Management Plan (AMP) 2026 Addendum[5]. The increase is driven by the commencement of construction on the St. Laurent Replacement Project included in the Proactive Vintage Steel Pipe Replacement Program, resulting in a $83.6 million increase in 2025, as well as higher Integrity spending (including EDIMP) of $11.4 million reflecting increased inspection driven repair activity. Additional increases occurred within the Proactive Service Replacement Program, which increased by $9 million to accelerate the removal of AMP fittings. Spending in the Proactive Vintage Plastic Replacement Program (Aldyl A) increased by $4.6 million, reflecting the completion of projects that had been deferred following the Phase 1 decision[6]. Overall, the variance reflects timing and execution of risk driven programs and previously deferred scope, rather than changes in program intent or risk tolerance.

d) Distribution Stations

- These assets are typically above grade facilities designed to reduce the operating pressure of natural gas pipeline systems through pressure control and over pressure protection. These facilities are used to transmit and/or distribute natural gas to reduced operating pressure pipeline systems which supply natural gas to cities and towns.

[4] EB-2025-0064, Exhibit 2, Tab 5, Schedule 5.
[5] EB-2020-0091.
[6] EB-2022-0200, Decision and Order, December 21, 2023.

- 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[7] 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. Additional increases were driven by Civil Replacements $3.0 million and the Customer Station Replacement Program $2.8 million, both increases are attributed to elimination of known risks. Spending also increased in the Compliance Remediation Program $1.6 million and the Obsolete Heating Equipment Program $1.2 million to eliminate known integrity, safety, and operability risks.

e) Fleet & Equipment

- The Fleet, Equipment and Tools asset class includes the vehicles, trailers, heavy equipment and tools owned by Enbridge Gas to support its business needs.
- Fleet & Equipment increased by $17.9 million in 2025 compared to 2024 driven by accelerated replacement of assets that are well beyond lifecycle replacement age, aimed at reducing operational downtime, improving fuel efficiency, and mitigating rising maintenance costs. Approximately 40% of the fleet and equipment portfolio is outside optimal replacement age, resulting in higher maintenance costs and reduced reliability compared to newer assets. In 2025, Fleet Vehicles spending increased by $5.3 million and Equipment increased by $2.1 million, reflecting execution of

[7] EB-2022-0200.

replacement activity that had been paced in prior years. In addition, Tools capital increased by $10.6 million, driven by required new and replacement tooling to ensure continued compliance with engineering and safety standards, particularly for tapping and stopping activities.

f) Growth – Distribution System Reinforcement

- The Growth asset class includes broad-based reinforcement projects designed to maintain system capacity when constraints are identified driven by forecasted load growth, evolving supply and demand patterns, and changes in system operating requirements. These reinforcements support the continued safe and reliable delivery of natural gas to existing and new customers and include projects that address new operating requirements such as hydrogen blending and hydrogen-ready infrastructure.
- The Growth – Distribution System Reinforcement asset class increased by $5.4 million in 2025 compared to 2024. This is primarily due to planning and engineering for the Hydrogen Program. Distribution System Reinforcements remain largely consistent with prior forecasts, with a modest increase between 2024 and 2025. The year-over-year change is primarily attributable to the Mississauga Reinforcement project[8] advancing from the pre-planning stage into the LTC application, preparation, and filing phase, resulting in increased development and pre-construction expenditures in 2025.

g) Real Estate and Workplace Services

- The Real Estate and Workplace Services (REWS) asset class includes properties (buildings and land) and furnishings.
- There is a base spend that supports the lifecycle replacement of building systems. Variances are driven by the specific property purchases and renovations that occur in a given year. Land acquisitions are driven by

[8] EB-2025-0073.

market availability and are aligned with the long-term strategies described in the Asset Management Plan.

- REWS capital spending decreased by ($32.1 million) in 2025 compared to 2024, primarily reflecting the completion of several large, non-recurring facilities projects that drove elevated spending in prior years. The most significant reductions relate to the Ottawa Operations Centre consolidation ($23.9 million) and the Brockville Operations Centre new build ($4.9 million), both of which were completed or substantially complete by the end of 2024 and therefore did not generate comparable capital requirements in 2025. Additional reductions are associated with the completion of other discrete site specific initiatives, including the Dryden Operations Centre ($2.8 million), VPC Security Improvements ($1.9 million), and prior year leasehold and customer care improvements. These decreases were partially offset by ongoing base investment in building systems, property upgrades, and targeted new build activities to support safe and reliable operations.

h) Technology Information Services

- The Technology Information Services (TIS) asset class includes:
    - General Hardware (Laptops/Desktops and Desktop sustainment equipment, networks, servers and security);
    - Specialized Hardware (to support specific business needs such as meter reading equipment, call center network devices);
    - Software assets consist of packaged applications, developed applications, and application infrastructure software; and
    - Communications assets include mobile phones and field devices (such as GPS devices, push-to-talk radios, leak survey field technology, and truck modems).

- 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 $21.1 million. Additional increases reflect the Core Infrastructure and Security Renewal Program $4.4 million, Field Device Renewal Program $3.1 million.

i) Transmission Pipe and Underground Storage

- This asset class includes the pipelines that form the backbone of the gas transmission system as well as the underground storage reservoirs in St. Clair Township near Sarnia, Crowland Township in Welland, and in Chatham-Kent.Transmission Pipe and Underground Storage capital decreased by ($114.9 million) in 2025 compared to 2024, primarily reflecting timing associated with the completion of Panhandle Regional Expansion Project[9], which achieved its major completion milestone and was placed into service in December 2024, resulting in $134.2 million of capital spend in 2024 that did not recur in 2025. 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.

[9] EB-2022-0157.

j) Utilization

- The utilization asset class includes meter purchases, measurement & regulation systems at customer premises, below ground and internal piping systems after the meter, and customer-owned systems[10].
- Utilization capital decreased by ($26.5 million) in 2025 compared to 2024, primarily reflecting lower meter related spending driven by reduced customer activity and inventory timing effects. 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.

k) Extended Alliance (EA) Fixed Overheads

- The EA fixed overhead asset class includes cost for Alliance partner overheads.
- EA Fixed Overhead spend decreased ($2.1 million) in 2025 compared to 2024. 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.

l) Community Expansion

- Community expansion provides natural gas services to communities not currently using natural gas. In response to the Government of Ontario's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas, Enbridge Gas has filed

[10] For customer owned systems that are downstream of the meter, the asset class is accountable for inspection at the time of initial installation and after re-introduction of gas. Maintenance and remediation of these assets are the responsibility of the customer.

proposals with the OEB designed to facilitate enhanced access to natural gas for non-served rural, remote and First Nation communities, and businesses in Ontario.

- Community Expansion increased by $0.5 million in 2025 compared to 2024.The $0.5 million increase is primarily due to timing of project spend and contributions in aid of construction.

m) Other

- Other includes regulated non-core, project-specific capital investments, such as Renewable Natural Gas (RNG), Compressed Natural Gas (CNG), and Hydrogen Blending initiatives, which are advanced selectively based on business case readiness, external partnerships, and project maturity. Year-over-year variances in this category are therefore expected and reflect the timing and lifecycle stage of individual projects, rather than a steady or levelized investment profile.
- 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, partially offset by small increases across other projects in this asset class.

Enbridge Gas
Deferral & Variance Account
Actual & Forecast Balances

Line No.	Account Description	OEB Account Number	Col. 1 Forecast for clearance at July 1, 2027 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Total ($000's)	Col.4 Reference to Evidence
	EGI Commodity Related Accounts					
1.	Upstream Transportation Optimization V/A	179-201	(34,774.9)	(1,882.5)	(36,657.4)	Exhibit C-2-1
2.	UFG Volume V/A	179-203	10,558.8	408.1	10,966.9	Exhibit C-2-3
3.	UFG Price V/A	179-204	(3,557.1)	(138.2)	(3,695.4)	Exhibit C-2-4
4.	Total Commodity Related Accounts		(27,773.2)	(1,612.6)	(29,385.8)	
	EGI Non Commodity Related Accounts					
5.	Transportation from Dawn Service D/A	179-202	70.4	3.7	74.0	Exhibit C-2-2
6.	Deferral Clearing V/A	179-302	3,529.2	174.3	3,703.5	Exhibit C-2-5
7.	Parkway Delivery Obligation V/A	179-303	2,558.2	129.5	2,687.7	Exhibit C-2-6
8.	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	
9.	Pension & OPEB V/A	179-305	-	(4,909.1)	(4,909.1)	Exhibit C-2-7
10.	Facility Carbon Charge V/A	179-307	(742.7)	(99.8)	(842.4)	Exhibit C-2-8
11.	Customer Carbon Charge V/A	179-308	(2.1)	(0.2)	(2.2)	Exhibit C-2-9
12.	Carbon Charges Bad Debt D/A	179-309	6,948.4	417.7	7,366.1	Exhibit C-2-10
13.	Earnings Sharing Mechanism D/A	179-311	(24,300.0)	(932.7)	(25,232.7)	Exhibit C-2-11
14.	Tax V/A	179-312	(13,621.5)	(347.3)	(13,968.8)	Exhibit C-2-12
15.	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	
16.	Green Button Initiative D/A	179-320	-	-	-	
17.	Dawn Parkway Surplus Capacity D/A	179-323	(2,260.3)	(105.1)	(2,365.4)	Exhibit C-2-13
18.	Distribution Integrity Management Program D/A	179-326	213.0	12.2	225.2	Exhibit C-2-14
19.	Post Retirement True-Up V/A	179-328	(49,006.6)	(2,542.6)	(51,549.2)	Exhibit C-2-15
20.	Clean Fuel Regulation Credits D/A	179-330	(35.0)	(1.8)	(36.9)	Exhibit C-2-16
21.	Indigenous Working Group D/A	179-331	268.6	12.1	280.7	Exhibit C-2-17
22.	Cloud Computing Implementation Costs D/A	179-332	-	-	-	
23.	Average Use V/A	179-333	34,494.4	2,130.6	36,625.0	Exhibit C-2-18
24.	Getting Ontario Connected V/A	179-335	14,093.7	744.7	14,838.3	Exhibit C-2-19
25.	Disposition of Property D/A	179-336	(12,804.0)	(689.4)	(13,493.4)	Exhibit C-2-20
26.	LEAP Emergency Financial Assistance D/A	179-338	1,200.8	50.6	1,251.4	Exhibit C-2-21
27.	OEB Cost Assessment V/A	179-340	2,997.0	121.9	3,118.9	Exhibit C-2-22
28.	IRP System Pruning D/A (2024 & 2025)	179-341	388.0	26.9	414.9	Exhibit C-2-23
29.	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-	
30.	Total Non Commodity Related Accounts		(36,010.5)	(5,803.8)	(41,814.3)	
31.	Total EGI Accounts (for clearance)		(63,783.8)	(7,416.4)	(71,200.1)	
	EGD Rate Zone Commodity Related Accounts					
32.	Storage and Transportation D/A	179-88	3,126.8	276.9	3,403.8	Exhibit D-1-1
33.	Total Commodity Related Accounts		3,126.8	276.9	3,403.8	
	EGD Rate Zone Non Commodity Related Accounts					
34.	Open Bill Extension D/A	179-325	-	-	-	
35.	Total Non Commodity Related Accounts		-	-	-	
36.	Total EGD Rate Zone (for clearance)		3,126.8	276.9	3,403.8	
	Union Rate Zones Gas Supply Accounts					
37.	Unabsorbed Demand Costs Variance Account	179-108	4,881.6	240.3	5,121.9	Exhibit E-1-1
38.	Total Gas Supply Accounts		4,881.6	240.3	5,121.9	
	Union Rate Zones Storage Accounts					
39.	Short-Term Storage and Other Balancing Services	179-70	(599.3)	(22.9)	(622.2)	Exhibit E-1-2
40.	Total Storage Accounts		(599.3)	(22.9)	(622.2)	
41.	Total Union Rate Zones (for clearance)		4,282.3	217.4	4,499.7	
42.	Total Deferral and Variance Accounts (for clearance)		(56,374.6)	(6,922.0)	(63,296.6)	
	EGI Accounts Not Being Requested For Clearance					
43.	Incremental Capital Module D/A	179-306	-	-	-	
44.	IRP Operating Costs Deferral Account	179-318	2,234.6	100.0	2,334.6	Exhibit C-2-24
45.	IRP Capital Costs Deferral Account	179-319	(3.0)	(0.1)	(3.1)	Exhibit C-2-24
46.	Panhandle Region Expansion Project V/A (2024-2025)	179-329	(10,199.5)	(643.5)	(10,843.0)	Exhibit C-2-24
47.	Site Restoration Costs Tracking Account	179-337	(15,615.7)	-	(15,615.7)	Exhibit C-2-24
48.	Asset Life Extension Costs D/A	179-343	-	-	-	

ACCOUNT NO. 179-201 UPSTREAM TRANSPORTATION OPTIMIZATION VARIANCE ACCOUNT

1. 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. The 2025 balance in this variance account is a credit to ratepayers of $34.775 million, plus interest.

2. In setting rates for 2024, the OEB approved a forecast of optimization revenue of $17.041 million[1]. Of that amount, 90% or $15.337 million, was credited to ratepayers in the OEB-approved 2024 rates.

3. The Company earned $55.679 million in net revenues from upstream transportation optimization during 2025. In accordance with the OEB-approved sharing methodology, 90% of this net revenue, or $50.111 million, is to be credited to customers. As stated above, $15.337 million has already been credited through rates; therefore, the deferral balance is a credit to ratepayers of $34.775 million ($50.111 million less $15.337 million). The primary driver for the incremental net revenue from upstream transportation optimization is capacity constraints in the U.S. Northeast, which resulted in elevated prices and incremental demand for exchanges. The majority of the exchanges were to Iroquois (New York/Ontario border) and East Hereford (New Hampshire/Québec border).

4. Table 1 provides a summary of the calculation of the balance in this variance account.

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

Table 1
Upstream Transportation Optimization Variance Account

Line No.	Particulars ($ millions)	2024 OEB-Approved (a)	2024 Actual (b)	2025 Actual (c)
1	Upstream Transportation Optimization Revenue	17.0	54.1	55.7
2	Shareholder Incentive (10%)	1.7	5.4	5.6
3	Ratepayer portion (90%)	15.3	48.7	50.1
4	Less: Gas Optimization Margin included in Rates	15.3	15.3	15.3
5	Variance Account Balance (line 3 - line 4)	-	33.4	34.8

ACCOUNT NO. 179-202 TRANSPORTATION FROM DAWN SERVICE DEFERRAL ACCOUNT

1. Enbridge Gas offers a transportation service from Dawn that is available to Union North T-Service (unbundled) customers between Dawn and the TransCanada delivery area where the customers' facilities are located. This service is referred to as the Base Service. The purpose of this transportation service is to provide these customers with a method to transport gas they acquire at Dawn to their TransCanada delivery area. In order for the Company to offer this service, it had to make long-term contractual commitments with TransCanada, and customers that chose to contract for this service were required to make the same commitment to the utility. The service allows the customer to reduce their contracted transportation service quantity should there be significant reductions in their contracted distribution service.

2. This account captures the difference between revenues and costs for the excess capacity from Parkway to the Union NDA, Union NCDA and Union EDA as part of the Base Service offering of the Transportation from Dawn Service.

3. The balance in this deferral account is a debit of $0.070 million, plus interest. The balance of $0.070 million represents the difference between the TransCanada capacity costs incurred by Enbridge Gas of $1.943 million and the revenues collected from customers of $1.873 million. The net variance is driven by a reduction of 480 GJ per day of contracted quantity by Union North T-service customers.

ACCOUNT NO. 179-203 UFG VOLUME VARIANCE ACCOUNT

1. The purpose of the Unaccounted for Gas Volume Variance Account (UFGVVA) is to capture the cost associated with the volumetric variances between the actual volume of unaccounted for gas (UFG) and the OEB-approved UFG volume. The UFGVVA was established in 2024 as part of Phase 1 of the 2024 Rebasing Application[1] in recognition of the need to record gas costs associated with variances between the actual UFG volumes and the forecast UFG volumes. Enbridge Gas and ratepayers will share on a 50/50 basis the cost or credit of variances between the OEB-approved UFG volume[2] of 243,681.5 10^3m^3 included in rates and the actual UFG volumes, at the applicable gas supply reference price, up to maximum total actual UFG volume of 400,000 10^3m^3. This evidence provides details regarding 2025 balances recorded in the UFGVVA.

2. Actual UFG volumes for 2025 for Enbridge Gas were determined to be 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. Attachment 1 provides the detailed calculations of the UFGVVA balance.

[1] EB-2022-0200.
[2] EB-2022-0200, Settlement Agreement, August 17, 2023, Exhibit O1, Tab 1, Schedule 2, Accounting Orders. p.22.

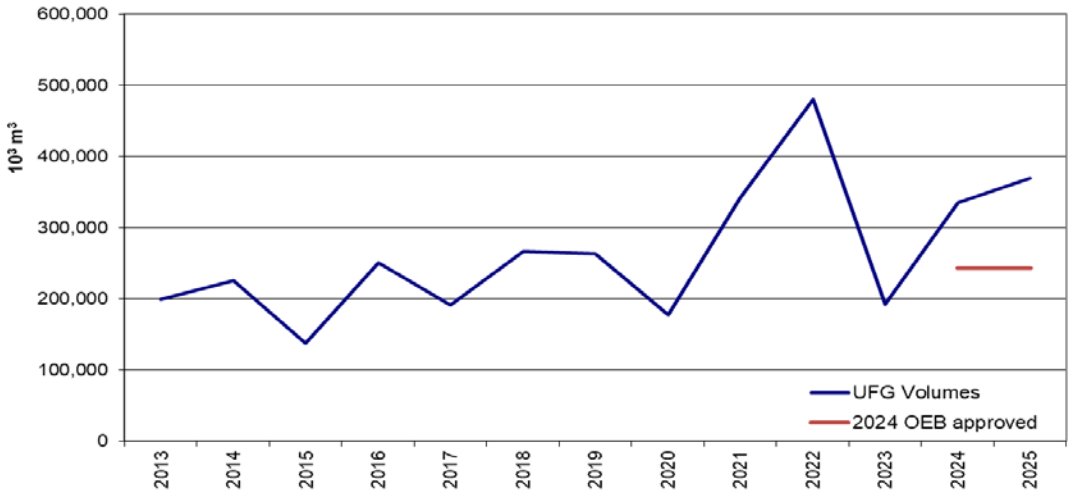
5. Table 1 provides historical UFG volumes for Enbridge Gas from 2013 to 2025.

Table 1
Historical UFG Volumes for EGI (Regulated)

Line No.	Particulars	UFG Volumes (10^3 m^3)
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
10	2022	480,301
11	2023	192,110
12	2024	334,888
13	2025	370,109

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

Figure 1: Historical Unaccounted For Gas Volumes (10^3m^3)

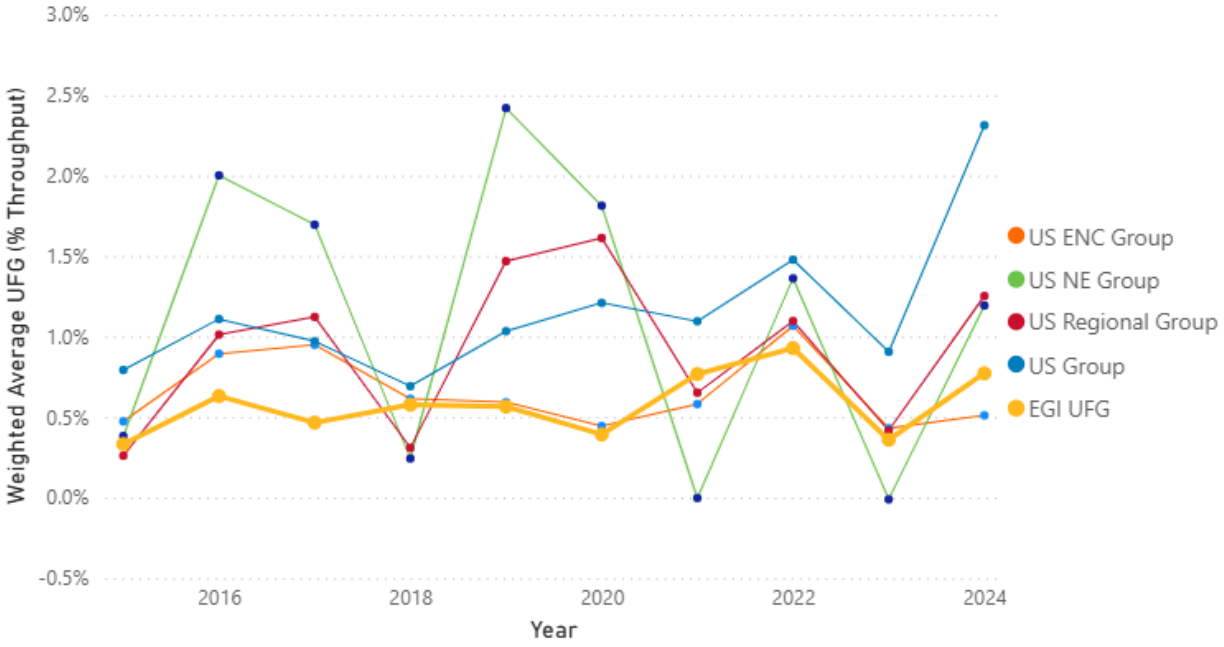


7. The 2019 Report on Unaccounted for Gas prepared by ScottMadden Management consultants filed in the Company's 2020 Rates Application (the 2019 UFG Report) included a UFG Benchmark Analysis for the period of 2008 to 2017. Based on the results of the analysis completed, ScottMadden noted that from 2008 to 2017 Enbridge Gas had demonstrated lower average UFG volumes than comparative gas utilities.

8. For the purposes of the current Application, Enbridge Gas gathered the most current publicly available data for the same comparative gas utilities (up to and including 2024 for comparative utilities and 2025 for the Company) and updated the benchmark analysis set out in the 2019 UFG Report.

9. Consistent with last year, the 2025 Benchmark Analysis represented in Figure 2 recognizes the relative size of each utility within a comparator group by determining the groups weighted average UFG by volume of throughput.

Figure 2: 2024 UFG Benchmark Analysis[3]



10. Enbridge Gas's total system (utility and non-utility) UFG in 2025 amounted to approximately 435,240 10^3m^3 compared to total system throughput for that same year of approximately 56,875,530 10^3m^3 (0.77%).

11. Figure 2 demonstrates that all utilities included in the benchmark analysis experienced similar volatility in UFG over time. As noted in its most recent Decisions regarding UFG costs and related rate riders for AltaGas and ATCO, the Alberta Utilities Commission stated:

[3] US ENC Group – Refers to the 15 largest utilities by throughput operating within the states of Illinois, Indiana, Michigan, Ohio and Wisconsin.
US NE Group – Refers to the 15 largest utilities by throughput operating within the states of New York, New Jersey, Pennsylvania, Connecticut, Massachusetts, Rhode Island, Vermont, New Hampshire and Maine.
US Regional Group – Refers to the 15 largest utilities by throughput operating within the states included in the US ENC Group or US NE Group.
US Group – Refers to the 15 largest utilities by throughput operating within the United States.

> In prior decisions, the Commission recognized that UFG is an expected element of operating a natural gas distribution system. The Commission also recognized that, due to the many factors that impact UFG, the UFG amount will fluctuate over time.[4]

12. Figure 2 reflects certain industry-wide trends across comparative utilities. It is reasonable to assume that such trends in UFG volumes may be reflective of common factors which have the potential to impact UFG volumes or costs broadly across the industry. Figure 2 shows that Enbridge Gas's UFG volumes are generally lower as a percent of throughput relative to its peers. Furthermore, the annual fluctuations in Enbridge's UFG volumes are generally less volatile than other gas utilities.

[4] Alberta Utilities Commission, Decision 27552-D01-2022 (September 12, 2022), 2022-2023 Unaccounted-For Gas Rider E and Rider H. (Apex Utilities Inc.), pp. 2-4; and Alberta Utilities Commission, Decision 28406-D01-2022 (October 17, 2022), 2023 Unaccounted-For Gas Rider D and Rider P. (ATCO Gas and Pipelines Inc.), pp.2-4.

EGI 2025 Unaccounted For Gas Variance Account

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Budget UFG (10^3m^3)	35,609	33,389	29,502	20,727	13,250	10,481	10,014	10,962	10,246	14,836	23,786	30,880	243,682
2	Weighted Average Reference Price ($/$10^3m^3$)	144.690	144.690	144.690	189.095	189.095	189.095	184.645	184.645	184.645	169.505	169.505	169.505	
3	Budget UFG ($ millions) (1)	5.2	4.8	4.3	3.9	2.5	2.0	1.8	2.0	1.9	2.5	4.0	5.2	40.2
4	Total Actual UFG (10^3m^3)	47,480	45,857	42,115	28,545	17,788	16,832	20,489	20,023	19,187	25,560	38,946	47,286	370,109
5	Weighted Average Reference Price ($/$10^3m^3$)	144.690	144.690	144.690	189.095	189.095	189.095	184.645	184.645	184.645	169.505	169.505	169.505	
6	Actual UFG ($ millions) (2)	6.9	6.6	6.1	5.4	3.4	3.2	3.8	3.7	3.5	4.3	6.6	8.0	61.5
7	UFG Volume Variance (10^3m^3) (3)	11,871	12,468	12,614	7,819	4,538	6,351	10,475	9,061	8,941	10,724	15,161	16,406	126,428
8	UFG Volume Variance ($ millions) (4)	1.7	1.8	1.8	1.5	0.9	1.2	1.9	1.7	1.7	1.8	2.6	2.8	21.3
9	50/50 Cost Sharing (5)													10.7
10	Damages Recovery ($ millions)													(0.1)
11	UFG Volume Variance ($ millions) (6)													10.6

Notes:

(1) Line 1 x Line 2.
(2) Line 4 x Line 5.
(3) Line 4 - Line 1.
(4) Line 6 - Line 3.
(5) Line 8 x 50%.
(6) Line 9 + Line 10.

ACCOUNT NO. 179-204 UFG PRICE VARIANCE ACCOUNT

1. The purpose of the UFG Price Variance Account is to capture the cost of gas associated with the price variance on gas supply purchases related to UFG. The price variance is calculated as the difference between the actual price of Enbridge Gas's gas supply purchases and the applicable gas supply reference price, applied to the actual experienced UFG volumes. The UFG Price Variance Account was established in 2024 as part of Phase 1 of the 2024 Rebasing Application[1].

2. Price variances are initially recorded in the PGVA for the respective rate zones and the portion of the price variances associated with UFG volumes is transferred from the PGVA to the UFG Price Variance Account. This transfer ensures that costs are borne by the appropriate group of ratepayers, consistent with the UFG cost allocation. The total balance in the UFG Price Variance Account is a payable to ratepayers of $3.56 million, plus interest.

1. EGD Rate Zone

3. During 2025, the Company purchased 152,715 10^3m^3 of gas supply in EGD rate zone related to actual UFG volumes on behalf of ratepayers.

4. The average actual cost of the UFG purchases in 2025 is $\$25.96/10^3m^3$ lower than the OEB-approved reference prices included in rates based on the EGD rate zone gas portfolio cost of $\$194.78/10^3m^3$. The result is a $3.96 million balance payable to ratepayers, as shown in Table 1. Attachment 1, page 1, provides the detailed calculation supporting the price variance of $\$25.96/10^3m^3$.

[1] EB-2022-0200.

Table 1
Calculation of 2025 EGD Rate Zone UFG Price Variance

Line No.	Particulars	Deferral Calculation
1	UFG Volumes (10^3m^3) – Company Supplied (1)	152,715
2	Price Variance ($/$10^3m^3$) (2)	($25.96)
3	Variance Account Balance ($ millions)	($3.96)

Notes:
(1) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.
(2) See Attachment 1, page 1 for the price variance calculation

2. Union Rate Zone

5. During 2025, the Company purchased 123,214 10^3m^3 of gas supply in Union rate zones related to actual UFG volumes on behalf of ratepayers. The actual UFG purchases exclude the actual UFG collected from ratepayers who provide UFG in kind as part of customer supplied fuel (CSF).

6. The average actual cost of the UFG purchases in 2025 is $3.30/$10^3m^3$ higher than the OEB-approved reference prices included in rates based on the Union South rate zone gas portfolio cost of $176.88/$10^3m^3$. The result is a $0.41 million balance receivable from ratepayers, as shown in Table 2. Attachment 1, page 2, provides the detailed calculation supporting the price variance of $3.30/$10^3m^3$.

Table 2
Calculation of 2025 Union Rate Zone UFG Price Variance

Line No.	Particulars	UFG Volumes (10^3m^3)
1	Experienced Regulated UFG	217,394
2	UFG Collected through CSF	94,180
3	UFG Volumes – Company Supplied (1)	123,214
		Deferral Calculation
4	UFG Volumes (10^3m^3) – Company Supplied (1)	123,214
5	Price Variance ($/$10^3m^3$) (2)	$3.30
6	Variance Account Balance ($ millions)	$0.41

Notes:
(1) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.
(2) See Attachment 1, page 2 for the price variance calculation.

Calculation of 2025 EGD Rate Zone Price Variance

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average Price
1	OEB-approved Reference Price ($ / 10^3m^3)	$166.82	$166.82	$166.82	$211.15	$211.15	$211.15	$208.56	$208.56	$208.56	$192.57	$192.57	$192.57	$194.78
2	Actual Purchase ($)	$220,512,467	$196,950,889	$133,099,934	$82,702,950	$86,992,488	$80,308,654	$88,636,454	$75,322,485	$59,408,282	$73,608,893	$95,513,659	$251,826,729	
3	Purchase Volumes (10^3m^3)	1,200,578	1,017,151	646,870	477,789	550,092	531,357	605,032	552,482	444,181	535,164	529,161	1,115,434	
4	Average Purchase Cost ($ / 103m3) (1)	$183.67	$193.63	$205.76	$173.09	$158.14	$151.14	$146.50	$136.33	$133.75	$137.54	$180.50	$225.77	$168.82
5	EGD Rate Zone Price Variance ($ / 10^3m^3) (2)	$16.85	$26.81	$38.94	($38.05)	($53.00)	($60.01)	($62.07)	($72.23)	($74.82)	($55.03)	($12.07)	$33.19	($25.96)

Notes
(1) Line 2 / Line 3
(2) Line 4 - Line 1

Calculation of 2025 Union Rate Zone Price Varaince

Line No.	Particulars	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average Price
1	OEB-approved Reference Price ($ / 10^3m^3)	$146.74	$146.74	$146.74	$199.47	$199.47	$199.47	$188.94	$188.94	$188.94	$172.39	$172.39	$172.39	$176.88
2	Actual Purchase ($)	$68,137,005	$90,060,436	$63,011,240	$42,121,343	$37,848,330	$50,299,405	$52,453,160	$49,116,287	$53,691,661	$71,681,043	$46,821,355	$120,631,336	
3	Purchase Volumes (10^3m^3)	332,359	412,940	301,545	220,221	238,320	331,657	340,535	315,000	373,621	487,698	240,498	517,483	
4	Average Purchase Cost ($ / 10^3m^3) (1)	$205.01	$218.10	$208.96	$191.27	$158.81	$151.66	$154.03	$155.92	$143.71	$146.98	$194.69	$233.11	$180.19
5	Union Rate Zone Price Variance ($ / 10^3m^3) (2)	$58.27	$71.35	$62.22	($8.20)	($40.66)	($47.81)	($34.90)	($33.01)	($45.23)	($25.41)	$22.30	$60.72	$3.30

Notes
(1) Line 2 / Line 3
(2) Line 4 - Line 1

ACCOUNT NO. 179-302 DEFERRAL CLEARANCE VARIANCE ACCOUNT

1. This account, approved by the OEB in its 2024 Rebasing Phase 1 Interim Rate Order,[1] records amount receivable from/(payable to) customers which reflects disposition variances in relation to the clearance of deferral and variance account balances authorized by the OEB. Disposition variances result from Enbridge Gas's billing systems' inability to locate and apply deferral clearance unit rates to all intended customers and/or volumes. Due to customer moves and other account changes, deferral clearance unit rates derived utilizing historical customers and volumes are not able to be assessed against all historical customers and/or volumes at the time of disposition, resulting in the balances captured in the Deferral Clearing Variance Account.

2. The balance in this variance account is a debit of $3.529 million, plus interest. The balance includes the residual amounts not disposed of from the following deferral dispositions: 2022 DSM[2] cleared between July 1, 2025 to August 31, 2025, and 2023 Federal Carbon Pricing Program cleared effective April 2025[3]. The total forecast disposition balance of these proceedings combined was a debit of $55.830 million, total recoveries were a credit of $52.301 million, resulting in a net residual debit balance of $3.529 million. A summary is provided in Table 1.

[1] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024.
[2] EB-2024-0193.
[3] EB-2024-0251.

Table 1
Deferral Clearing Variance

Line No.	Proceeding	Amount ($ millions)
1	2022 DSM Deferral Disposition (1)	53.840
2	2023 Federal Carbon Pricing Program (2)	1.990
3	Subtotal – Approved for Disposition in 2025	55.830
4	Amounts disposed of in 2025 through rider and billing adjustments	(52.301)
5	Residual balance to Deferral Clearing Variance Account	3.529

Notes:
(1) EB-2024-0193.
(2) EB-2024-0251.

3. 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.

ACCOUNT NO. 179-303 PARKWAY DELIVERY OBLIGATION VARIANCE ACCOUNT

1. In Union's 2014 Rates Settlement Agreement[1], parties agreed to permanently shift the Union South direct purchase (DP) Parkway Delivery Obligation (PDO) to Dawn over time. The parties also agreed to the payment of a Parkway Delivery Commitment Incentive (PDCI) for any continuing obligated Daily Contract Quantity (DCQ) deliveries at Parkway beginning November 1, 2016. The mechanism was extended and remained in place during the 2019 to 2023 deferred rebasing term following the MAADs Decision[2]. In Phase 1 of the 2024 Rebasing proceeding[3], parties agreed to revisions to the PDO Framework and the 2024 PDCI Forecast.

2. This evidence will support the balance in the Parkway Delivery Obligation Variance Account (PDOVA) and the commitment to provide annual updates on the PDO reduction and PDCI costs from the 2024 Rebasing Phase 1 Settlement Agreement[4]. The evidence is organized as follows:
    1. 2025 PDOVA
    2. Annual PDO Reporting

1. 2025 PDOVA

3. This account records the difference between the actual Dawn Parkway System demand and fuel costs associated with any PDO shift, as well as the actual Parkway PDCI costs incurred by Enbridge Gas, and the PDO and PDCI costs included in rates as approved by the OEB. Dawn Parkway System demand and fuel costs associated with up to 89 TJ/d of Dawn Parkway surplus capacity used to reduce the PDO and already included in rates are not recorded in this account.

[1] EB-2013-0365.
[2] EB-2017-0306/EB-2017-0307, OEB Decision and Order, August 30, 2018.
[3] EB-2022-0200.
[4] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1 Schedule 1, August 17, 2023.

4. The balance in this deferral account is a debit of $2.558 million, plus interest. The balance of $2.558 million represents the difference between the OEB-approved PDCI cost of $14.150 million recovered in rates and the actual PDCI cost of $16.708 million. Higher PDCI cost is primarily attributed to higher actual PDCI volumes than the forecast PDCI volumes of 79 PJ.

2. Annual PDO Reporting

5. The purpose of this section of evidence is to provide an update on PDO reduction efforts for 2025. As agreed to in the 2024 Rebasing Phase 1 Settlement Agreement[5], Enbridge Gas committed to provide details regarding:

    a. Capacity that could become available in the following two years that could be used to further reduce the PDO;
    b. Potential market-based solution alternatives to reduce the PDO;
    c. Forecast PDO volumes for the two years following the current year; and
    d. The measures considered and used to reduce the PDO in the current year.[6]

2.1 Potential Capacity Availability

6. There is no excess capacity available on the Dawn-Parkway system, and there is no capacity expected to become available to reduce the PDO over the next two years. In 2025, Enbridge Gas issued an operational notice informing shippers of a pressure restriction on the NPS 26 Trafalgar pipeline. That restriction will remain in effect until further notice.

2.2 Potential Market-based Solution Alternatives

7. As mentioned above, Enbridge Gas issued an operational notice informing shippers of a pressure restriction on the NPS 26 Trafalgar pipeline in 2025. In light of the restriction, a PDO shift to Dawn was not practical.

[5]EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023.
[6]EB-2022-0200, Exhibit 4, Tab 7, Schedule 1, p.9.

2.3 PDO Forecast

8. The DP customer PDO forecast on November 1, 2026, is 255 TJ/d, which excludes the addition of approximately 13 TJ/D for DP customers in the EGD rate zone with a PDO, as outlined in Phase 3 of the 2024 Rebasing Application[7]. The DP customer PDO forecast inclusive of customers in the EGD rate zone with a PDO on November 1, 2026, is 268 TJ/d.

9. The DP customer PDO forecast on November 1, 2027, is 265 TJ/d, which excludes the addition of approximately 13 TJ/D for DP customers in the EGD rate zone with a PDO, as proposed in Phase 3 of the 2024 Rebasing Application[8]. The DP customer PDO forecast inclusive of customers in the EGD rate zone with a PDO on November 1, 2027, is 278 TJ/d.

2.4 Measures Taken in the Current Year

10. For the reasons set out above, Enbridge Gas was not able to shift any PDO in 2025.

[7] EB-2025-0064, Exhibit 8, Tab 2, Schedule 2.
[8] Ibid.

ACCOUNT NO. 179-305 PENSION AND OPEB VARIANCE ACCOUNT

1. In the OEB Report to all regulated entities, titled *"Regulatory Treatment of Pension and Other Post-employment Benefits (OPEB) Costs",* the OEB ordered the establishment of the deferral account, effective January 1, 2018, to be used by utilities that are approved to recover their pension and OPEB costs on an accrual basis[1]. The Company recovers its pension and OPEB costs on an accrual basis.

2. The purpose of the Pension and OPEB Variance Account is to track the differences between forecast accrual pension and OPEB amounts recovered in rates, and the actual cash payments made for both pension and OPEB, on a go-forward basis from the date the account was established.

3. The forecast accrual reference amount that will be used to calculate the entries recorded assumes that the total gross accrual cost as determined by actuarial valuation is what is recorded in the Company's total operating and maintenance expense. The actual cash payments would include all cash payments the utility makes for its pension and OPEB obligations. The approved accrual amount in rates will not change or escalate during the IR term.

4. In the Phase 1 Interim Rate Order[2], the OEB approved the harmonization of the Pension and OPEB Variance Account (Account No.179-305). As part of this harmonization Enbridge Gas proposed to combine the ending December 31, 2023, cumulative primary balances for the EGD and Union rate zones, along with the associated contra balances, as a starting point for Enbridge Gas as of January 1, 2024. Interest will continue to be calculated monthly on the balance when

[1] EB-2015-0040, *Regulatory Treatment of Pension and Other Post-employment Benefits ("OPEB") Costs*, September 14, 2017, p. 2.
[2] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024.

the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, as a payable to ratepayers.

5. The OEB-approved pension expense was a credit ($1.6) million and the actual cash payments made for both pension and OPEB were $13.8 million, resulting in an annual $15.4 million debit variance. As such the variance carried forward from 2024 is a $122.8 million credit variance, plus the 2025 debit of $15.4 million result in a cumulative ending credit balance at the end of 2025 of $107.4 million credit variance through the end 2025.

6. In accordance with the OEB's Report[3], when the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, an asymmetrical carrying charge, to be returned to ratepayers, should be accrued based on the opening monthly difference between amount recovered in rates and actual cash payments. The balance in the account for 2025 is an interest credit to ratepayers of $4.9 million to December 31, 2025.[4] Table 1 sets out the detailed calculation of the forecast accrual versus actual cash payments, and associated interest.

[3] EB-2015-0040, *Regulatory Treatment of Pension and Other Post-employment Benefits ("OPEB") Costs*, September 14, 2017.
[4] Interest is as of December 31, 2025, as interest on this account is calculated on a cumulative account balance basis.

Table 1
Details Of 2025 Interest Calculated on Forecast Accruals vs Actual Cash Payments
In Pension and OPEB Variance Account (No. 179-305)

Line No.	Particulars ($000's)	24-Dec	25-Jan	25-Feb	25-Mar	25-Apr	25-May	25-Jun	25-Jul	25-Aug	25-Sep	25-Oct	25-Nov	25-Dec	Total
1	Forecast accrual amounts		(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(136)	(1,633)
2	Actual cash payments		3,120	565	1,228	484	437	1,135	374	397	742	755	397	4,148	13,782
3	Monthly variance		3,256	701	1,364	620	573	1,271	510	533	878	891	533	4,284	15,415
4	Cumulative variance	(122,833)	(119,577)	(118,876)	(117,511)	(116,891)	(116,319)	(115,048)	(114,538)	(114,005)	(113,127)	(112,235)	(111,703)	(107,418)	
5	OEB prescribed CWIP rate		4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	
6	Asymmetrical interest		(0.433)	(0.422)	(0.419)	(0.414)	(0.412)	(0.410)	(0.406)	(0.404)	(0.402)	(0.399)	(0.396)	(0.394)	(4.909)

ACCOUNT NO. 179-307 - FACILITY CARBON CHARGE VARIANCE ACCOUNT

1. Enbridge Gas is requesting a credit to ratepayers of $0.74 million, plus interest, in the Facility Carbon Charge Variance Account (FCCVA).

2. In June 2018, the Greenhouse Gas Pollution Pricing Act (GGPPA) was enacted. Under the GGPPA, a federal carbon pricing program (FCPP) applies in whole or in part to any province or territory that requested it or that did not have an equivalent carbon pricing system in place by January 1, 2019. Provinces or territories can submit their own carbon pricing systems to the federal government for approval, and, if approved, are not subject to Part 1 and/or Part 2 of the GGPPA.

3. The federal government confirmed in October 2018 that the GGPPA would apply in Ontario. In March 2022, the federal government announced that, effective January 1, 2022, Ontario's carbon pricing system for industrial emitters, known as the Emissions Performance Standards (EPS) program, would be implemented in Ontario, effectively removing the province from Part 2 of the GGPPA.

4. On March 15, 2025, the federal government set the Federal Carbon Charge rate to $0.00 per cubic metre of marketable natural gas, effective April 1, 2025, through amending regulations under the federal GGPPA[1]. Accordingly, Enbridge Gas removed the Federal Carbon Charge from customer bills effective April 1, 2025.

5. In 2025, in Ontario, the FCPP was composed of two elements: (i) a charge on fossil fuels (the Federal Carbon Charge) imposed on distributors, importers, and producers; and (ii) an Ontario EPS program for prescribed industrial facilities.

[1] Government of Canada. (2025 March 15). Regulations Amending Schedule 2 to the Greenhouse Gas Pollution Pricing Act and the Fuel Charge Regulations: SOR/2025-107. gazette.gc.ca/rp-pr/p2/2025/2025-03-15-x2/html/sor-dors107-eng.html

6. Despite the federal government setting the Federal Carbon Charge rate to $0.00 per cubic metre of marketable natural gas as of April 1, 2025, the Ontario EPS program remains in effect. Enbridge Gas must continue to comply with the Ontario EPS Regulations, thus incurring facility related costs associated with the Company's annual EPS compliance obligations. Enbridge Gas will keep the FCCVA open to capture the variances between actual facility related costs and facility related costs recovered in rates.

7. In 2025, Enbridge Gas's operations as a natural gas utility in Ontario fell under the purview of the GGPPA and EPS Regulation, which resulted in facility-related costs (Facility Carbon Charge) being incurred and tracked through the FCCVA.

8. Enbridge Gas's facility-related volumes and associated costs are composed of Company Use Volumes (facilities which are not covered under the EPS) from January 1, 2025 to March 31, 2025, and EPS Volumes (facilities which are covered under the EPS) from January 1, 2025 to December 31, 2025.

9. From January 1 to March 31, 2025, Enbridge Gas's Company Use Volumes were subject to the Federal Carbon Charge. This charge applied to Enbridge Gas's own fuel use within its distribution system (i.e. its Company Use Volumes for distribution buildings, boiler/line heaters, and Natural Gas Vehicle (NGV) fleet fuel). Enbridge Gas is required to remit the Federal Carbon Charge on its Company Use Volumes to the Government of Canada monthly.

10. Enbridge Gas's EPS Volumes are related to the fuel used in the Company's natural gas transmission and storage compressor facilities. For 2025, these operations continued to fall under the Ontario EPS Regulation, requiring the Company to remit payment annually to the provincial government for any emissions that exceed the registered EPS facility's total annual emissions limit. Under the EPS Regulation, for

each tonne of emissions that exceed the annual limit, an EPS participant can either pay the excess emissions charge[2] or submit emissions performance units (EPUs) issued by the provincial government, to satisfy their annual EPS compliance obligation.

11. The costs associated with Enbridge Gas's Company Use Volumes and EPS Volumes are recovered from customers as part of the Facility Carbon Charge, which is included in delivery or transportation charges on customers' bills. As approved by the OEB through Enbridge Gas's 2024 FCPP Application, the Facility Carbon Charge rate from January 1 to March 31, 2025, was 0.0143 cents per cubic metre (cents/m^3)[3]. From April 1 to June 30, 2025, the Facility Carbon Charge rate was 0.0172 cents/m^3 as approved by the OEB through Enbridge Gas's 2025 FCPP Application[4]. On July 1, 2025, the Facility Carbon Charge rate was updated to 0.0123 cents/m^3 through the quarterly rate adjustment mechanism[5], as Company Use Volumes were no longer being subject to the Federal Carbon Charge. Based on actual customer volumes, $7.89 million in revenue was billed through the Facility Carbon Charge from January 1 to December 31, 2025.

12. Enbridge Gas's 2025 facility-related obligation was $8.76 million ($1.08 million related to Company Use Volumes and $7.68 million related to EPS Volumes), of which $7.14 million is attributable to Enbridge Gas's regulated utility operations[6].

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[2] Excess emissions charge is the price per unit in $/tCO2e. For the 2025 compliance period, the excess emissions charge is $95/tCO2e. https://www.ontario.ca/laws/regulation/190241.
[3] EB-2023-0196, OEB Decision and Order, February 8, 2024, pp.5-6.
[4] EB-2024-0251, OEB Decision and Order, February 28, 2025, pp.5-6.
[5] EB-2025-0165, OEB Decision and Interim Rate Order, pp. 7-8.
[6] Enbridge Gas's regulated costs are related to gas cost associated with the transmission and storage fuel consumed (compressor fuel) by regulated storage operations while the unregulated costs are related to the gas cost associated with the storage fuel consumed (compressor fuel) by the unregulated storage activities.

13. Enbridge Gas has recorded a 2025 facility-related variance of ($0.74 million), in the FCCVA[7]. This reflects a variance between the amount of revenue billed through the Facility Carbon Charge and Enbridge Gas's actual regulated facility-related costs, which is shown in Table 1.

Table 1
2025 FCCVA Balance

Line No.	Particulars ($ millions)	2025 Actual Costs
1	Facility Carbon Charge Revenue	$7.89
2	Company Use Costs	$(1.08)
3	EPS Costs	$(6.06)
4	Variance	$0.74

14. The main drivers of the variance, , were due to the delay in adjusting the Facility Carbon Charge rate following the unexpected change to Federal Carbon Charge and a slightly warmer than normal winter, as outlined below.

15. On April 1, 2025, Enbridge Gas retained the then-current Facility Carbon Charge rate and deferred the rate update to account for the removal of the Facility Carbon Charge on Company Use volumes, as approved by the OEB[8]. This delay in adjustment to the Facility Carbon Charge rate contributed to higher amounts of carbon charges being collected from customers between April to July in 2025. The EPS carbon costs were slightly lower than forecasted as the regulated EPS compressor fuel volumes and the associated emissions were lower than forecast due to a warmer winter with slightly lower system demands.

[7] This variance reflects consideration of: (i) applying the Federal Carbon Charge Rate for Marketable Natural Gas of 15.25 ¢/m^3 from January 1, 2025 – March 31, 2025 to actual Company Use Volumes of natural gas consumed in the operation of Enbridge Gas's facilities from January 1, 2025 to March 31, 2025; (ii) Enbridge Gas's 2025 EPS obligation of $6.06 million related to regulated utility operations for the January 1, 2025 to December 31, 2025 period; and (iii) actual billed amounts for the January 1, 2025 to December 31, 2025 period.
[8] EB-2025-0078.

1. EPS Compliance Costs

16. The $7.68 million[9] related to EPS Volumes is based on Enbridge Gas satisfying its entire 2025 EPS compliance obligation by paying the excess emissions charge of $95/t$CO_2$e. As the deadline to pay the 2025 EPS obligation is not until December 1, 2026, Enbridge Gas still has the option to satisfy its 2025 EPS obligation by purchasing EPUs from other EPS participants. EPUs typically sell at a discount to the excess emissions charge, which would reduce Enbridge Gas's 2025 EPS compliance obligation.

17. In June 2024, the provincial government introduced the Emissions Performance Program (EPP) which uses compliance payments collected through the EPS to support emissions reduction projects at eligible EPS registered facilities[10].

18. EPP funding is provisionally equal to a facility's EPS compliance payment(s) made to the provincial government in prior years. If an EPS participant purchases EPUs from another EPS participant for use towards their EPS compliance obligation, the EPS compliance payment to the provincial government would be reduced by the corresponding amount. Therefore, by utilizing EPUs for an EPS compliance obligation, an EPS facility forfeits or reduces the EPP funding that the provincial government would offer in following years.

19. Enbridge Gas will use the evaluation criteria outlined in response at Exhibit I.STAFF-2 of the 2025 FCPP Application, to determine the right balance between procuring EPUs to reduce the 2025 EPS compliance obligation or paying the excess emissions charge to secure EPP funding[11]. The ability to use EPUs to reduce the

[9] Includes costs related to both regulated and unregulated operations.
[10] Ontario Government, Available funding opportunities from the Ontario Government, Emissions Performance Program. September 4, 2024. https://www.ontario.ca/page/available-funding-opportunities-ontario-government#section-5
[11] EB-2024-0251, Exhibit I.STAFF.2 part a).

2025 EPS compliance obligation is also based on the availability of EPUs in the market, which to date have been limited.

20. Should Enbridge Gas's 2025 EPS obligation differ from what has been outlined in evidence, due to the Company procuring EPUs at a lower price than the excess emissions charge or due to any findings from the ongoing regulatory verification, any variances will be recorded in the 2026 FCCVA.

ACCOUNT NO. 179-308 - CUSTOMER CARBON CHARGE VARIANCE ACCOUNT

1. Enbridge Gas is requesting disposition of ($0.002 million), plus interest, in the Customer Carbon Charge Variance Account (CCCVA).

2. In June 2018, the Greenhouse Gas Pollution Pricing Act (GGPPA) was enacted. Under the GGPPA, a federal carbon pricing program (FCPP) applies in whole or in part to any province or territory that requested it or that did not have an equivalent carbon pricing system in place by January 1, 2019. Provinces or territories can submit their own carbon pricing systems to the federal government for approval, and, if approved, are not subject to Part 1 and/or Part 2 of the GGPPA.

3. The federal government confirmed in October 2018 that the GGPPA would apply in Ontario. In March 2022, the federal government announced that, effective January 1, 2022, Ontario's carbon pricing system for industrial emitters, known as the Emissions Performance Standards (EPS) program, would be implemented in Ontario, effectively removing the province from Part 2 of the GGPPA.

4. On March 15, 2025, the federal government set the Federal Carbon Charge rate to $0.00 per cubic metre of marketable natural gas, effective April 1, 2025, through amending regulations under the federal GGPPA[1]. Accordingly, Enbridge Gas removed the Federal Carbon Charge from customer bills effective April 1, 2025.

5. In 2025, in Ontario, the FCPP was composed of two elements: (i) a charge on fossil fuels (the Federal Carbon Charge) imposed on distributors, importers, and producers, which increased on April 1, 2024[2]; and (ii) an Ontario EPS program for prescribed industrial facilities.

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[1] Government of Canada. (2025 March 15). Regulations Amending Schedule 2 to the Greenhouse Gas Pollution Pricing Act and the Fuel Charge Regulations: SOR/2025-107. gazette.gc.ca/rp-pr/p2/2025/2025-03-15-x2/html/sor-dors107-eng.html

[2] The Federal Carbon Charge rate for marketable natural gas from January 1, 2025 to March 31, 2025 was 15.25 cents per cubic metre.

6. In 2025, Enbridge Gas's operations as a natural gas utility in Ontario fell under the purview of the GGPPA and EPS Regulation. Under the GGPPA, Enbridge Gas is registered as a Distributor and was required to remit customer-related Federal Carbon Charges to the Government of Canada monthly, for volumes delivered by Enbridge Gas to its residential, commercial, and industrial customers who are not covered under the EPS. These costs were recovered as a pass-through to customers in rates, as approved by the OEB through the 2025 FCPP Application[3].\

7. Enbridge Gas tracks the variance between actual customer-related carbon costs incurred and the customer-related carbon costs recovered in rates within the OEB-approved CCCVA.

8. In Phase 1 of the 2024 Rebasing Application, Enbridge Gas proposed to harmonize the established FCPP-related deferral and variance accounts effective January 1, 2024, including the CCCVAs, due to the Company being an amalgamated entity and no longer requiring separate deferral and variance accounts for the EGD and Union rate zones[4]. As part of the 2024 Rebasing Phase 1 Settlement Agreement, parties agreed on harmonizing the CCCVAs, and the OEB approved this in its Decision on the Settlement Agreement[5]. Accordingly, effective January 1, 2024, the harmonized account is the CCCVA – Enbridge Gas Inc. [6].

9. The CCCVA balance of ($0.002 million), plus interest, is a credit to ratepayers who were subject to the Federal Carbon Charge.

[3] EB-2024-0251.
[4] EB-2022-0200, Exhibit 9, Tab 1, Schedule 2, pp.24-25.
[5] EB-2022-0200, Settlement Agreement, August 17, 2023.
[6] Enbridge Gas Inc. Account No. 179-308, to record the variance between actual customer carbon costs and the customer carbon costs recovered in rates.

10. Under the GGPPA and associated Fuel Charge Regulations, RNG and hydrogen are not subject to the Federal Carbon Charge[7]. The variance recorded is due to deliveries of hydrogen to customers in January to March 2025, through the Company's Low Carbon Energy Project (LCEP). While the Company's renewable natural gas (RNG) OptUp program remains in effect, no purchases of RNG were carried out during the January to March 2025 period which would be eligible for exemption.

11. Due to billing system functionality constraints, Enbridge Gas was unable to reduce the Federal Carbon Charge only on the portion of a system supply customer's bill that was RNG or hydrogen. Given the limited quantity of exempt fuels delivered to customers, modifying the billing system to implement this functionality would have significantly increased administrative complexity and costs, for limited economic benefit to customers. Thus, Enbridge Gas applied the Federal Carbon Charge to all volumes of gas delivered to customers, including on RNG and hydrogen volumes. As RNG and hydrogen delivered by Enbridge Gas reduced the Company's Federal Carbon Charge obligations and subsequent remittance to the Government of Canada, any variance between the Federal Carbon Charges remitted to the Government of Canada and the amount charged to customers were tracked in the CCCVA, to be disposed to all customers subject to the Federal Carbon Charge[8].

12. The variance in the CCCVA for 2025 is minor due to hydrogen being distributed through the LCEP pilot project to a limited number of customers, which result in small volumes of hydrogen being eligible for exemption.

[7] Under the GGPPA, biomethane, also known as RNG, is exempt from the Federal Carbon Charge and on March 27, 2023, the Fuel Charge Regulations, enacted under the GGPPA, were amended to confirm that hydrogen blended with natural gas is exempt from the Federal Carbon Charge, retroactive to August 2022, https://www.gazette.gc.ca/rp-pr/p2/2023/2023-04-12/html/sor-dors62-eng.html.
[8] EB-2020-0066, OEB Decision and Order, September 24, 2020, pp.16-17.

1. Federal Carbon Charge Removal

13. On May 26, 2025, the *Notice of Ways and Means Motion to introduce a bill respecting certain affordability measures for Canadians and another measure*[9] was issued which further amended the GGPPA and provided a schedule for its phased repeal. Repeal of the GGPPA in its entirety will occur on April 1, 2035, and as such Enbridge Gas continues to have an obligation to apply and remit FCC for natural gas delivered prior to April 1, 2025. 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 lead to adjustments in Enbridge Gas's previously reported Federal Carbon Charge amounts which the Company will be obligated to report and remit to the Government of Canada.

14. Enbridge Gas will keep the CCCVA open to capture potential variances that could arise due to the removal and on-going wind-down of the Federal Carbon Charge. If balances are recorded in this account going forward, Enbridge Gas will request approval to dispose of the balances through a future application.

[9] Minister of Finance and National Revenue. (2025 May 26). Notice of Ways and Means Motion to introduce a bill respecting certain affordability measures for Canadians and another measure ita-lir-0525-l-bil.pdf

ACCOUNT NO. 179-309 - CARBON CHARGES BAD DEBT DEFERRAL ACCOUNT

1. Enbridge Gas is requesting disposition of $6.95 million, plus interest, in the Carbon Charges Bad Debt Deferral Account (CCBDDA).

2. Effective January 1, 2019, the federal government applied Part 1 and Part 2 of the Greenhouse Gas Pollution Pricing Act (GGPPA) in Ontario, implementing a carbon pricing system in the province known as the federal carbon pricing program (FCPP). In March 2022, the federal government announced that, effective January 1, 2022, Ontario's carbon pricing system for industrial emitters, known as the Emissions Performance Standards (EPS) program, would be implemented in Ontario, effectively removing the province from Part 2 of the GGPPA.

3. In 2024, in Ontario, the FCPP was composed of two elements: (i) a charge on fossil fuels (the Federal Carbon Charge) imposed on distributors, importers, and producers, which increased on April 1, 2024[1]; and (ii) an Ontario EPS program for prescribed industrial facilities.

4. In 2025, Enbridge Gas's operations as a natural gas utility in Ontario fell under the purview of the GGPPA and EPS Regulation. On March 15, 2025, the federal government set the Federal Carbon Charge (FCC) rate to $0.00 per cubic metre of marketable natural gas, effective April 1, 2025, through amending regulations under the federal GGPPA[2]. Accordingly, Enbridge Gas removed the FCC from customer bills effective April 1, 2025.

[1] The Federal Carbon Charge rate for marketable natural gas from January 1, 2025 to March 31, 2025, was 15.25 cents per cubic metre.
[2] Government of Canada. (2025 March 15). Regulations Amending Schedule 2 to the Greenhouse Gas Pollution Pricing Act and the Fuel Charge Regulations: SOR/2025-107. gazette.gc.ca/rp-pr/p2/2025/2025-03-15-x2/html/sor-dors107-eng.html

5. Prior to January 1, 2024, Enbridge Gas recorded administration costs, including carbon related bad debt, associated with the impacts of federal and provincial regulations related to greenhouse gas emissions requirements for Enbridge Gas within the two OEB-approved FCPP-related Greenhouse Gas Emissions Administration Deferral Accounts (GGEADAs)[3].

6. In the 2024 Rebasing Phase 1 Settlement Agreement, parties agreed to consolidating the GGEADAs into a single Enbridge Gas account, on the condition the GGEADA be renamed the CCBDDA and the scope of the account be limited to recording bad debt costs associated with carbon charges[4]. The OEB approved these account modifications, effective January 1, 2024, in its Decision on the Settlement Agreement[5].

7. In 2025, Enbridge Gas incurred $6.95 million bad debt costs associated with carbon charges, which was recorded in the CCBDDA. In its 2025 FCPP Application, Enbridge Gas forecast it would incur $13.05 million in incremental carbon related bad debt expenses in 2025 based on forecasted costs recoverable from customers as a result of the GGPPA and EPS Regulation[6].

8. As outlined in the 2022 Federal Carbon Pricing Program Application in the response at Exhibit I.VECC.7, the bad debt forecasting methodology distinguishes FCPP-related bad debt from “regular” bad debt by taking a percentage of the total Company bad debt based on the percentage of the total bill related to FCPP[7]. The contributing factor to the 2025 forecast variance was due to the FCC no longer being

[3] EB-2024-0251, Exhibit C, Tab 1, Schedule 1, pp.1-9.
[4] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, pp.53-55.
[5] EB-2022-0200, Settlement Agreement, August 17, 2023, p.1.
[6] EB-2024-0251, Exhibit A, Tab 2, Schedule 1, pp.7.
[7] EB-2021-0209, Exhibit I.VECC.7.

applied to customer fuel use after March 31, 2025, resulting in an overall reduction to FCPP-related bad debt.

1. Federal Carbon Charge Removal

9. On May 26, 2025, the *Notice of Ways and Means Motion to introduce a bill respecting certain affordability measures for Canadians and another measure*[8] was issued which further amended the GGPPA and provided a schedule for its phased repeal. Repeal of the GGPPA in its entirety will occur on April 1, 2035, and as such Enbridge Gas continues to have an obligation to apply and remit FCC for natural gas delivered prior to April 1, 2025. 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.

[8] Minister of Finance and National Revenue. (2025 May 26). Notice of Ways and Means Motion to introduce a bill respecting certain affordability measures for Canadians and another measure ita-lir-0525-l-bil.pdf

ACCOUNT NO. 179-339 EARNINGS SHARING MECHANISM DEFERRAL ACCOUNT

1. As part of the 2024 Rebasing Phase 2 Settlement Agreement,parties agreed to, and the OEB approved the establishment of the Earnings Sharing Mechanism (ESM) Deferral Account.[1] For the years 2025 through 2028, this account records the ratepayer share of utility earnings that results from the application of the earnings sharing mechanism. If in any year, the actual utility return on equity (ROE) exceeds the OEB-approved ROE (the 2024 allowed ROE of 9.21% embedded in base rates) by more than 100 basis points, the excess earnings will be shared equally (50/50) between ratepayers and the Company. Further, earnings over 300 basis points above the allowed ROE will be credited to ratepayers on a 90/10 basis.

2. As outlined in Exhibit B, Tab 1, Schedules 1 & 2, the Company was in an earnings sharing position for 2025, as the actual achieved ROE of 10.774% exceeded the OEB-approved earnings sharing benchmark ROE of 10.21% (9.21% approved ROE + 100 basis point deadband before sharing). This resulted in gross over earnings of $48.7 million to be shared equally between ratepayers and shareholders. Correspondingly, a credit of $24.3 million to ratepayers, plus interest, has been recorded in the Earnings Sharing Mechanism Deferral Account. Details of 2025 achieved earnings can be found throughout the B series of exhibits. The main drivers of the higher achieved ROE were colder weather and lower operating costs:

    a) Favorable weather in the year was due to a combination of a colder than normal first half of the year, as well as a much colder November and December. This resulted in higher heating demand compared to what would have occurred under normal weather conditions.

[1] EB-2024-0111, Settlement Agreement, November 29, 2024.

b) The operation and maintenance expenses of the Company were lower than expected primarily due to lower compensation and benefits costs incurred in 2025. Details of O&M are presented in Exhibit B, Tab 3, Schedule 1.

ACCOUNT NO. 179-312 TAX VARIANCE ACCOUNT

1. This account records 50% of the revenue requirement impact of any tax rate or rule changes, versus the tax rates and rules included in rates, that affect Enbridge Gas Inc., subject to the following two exceptions as per the approved accounting order:

> In accordance with the OEB's July 25, 2019, letter, Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance ("CCA"), within a sub-account of the Tax Variance Account, Enbridge Gas will record 100% of the revenue requirement impact of any changes in CCA rules that are not reflected in base rates. This will include impacts related to Bill C-97 CCA rule changes, which became effective November 21, 2018, as well as any future CCA changes instituted by relevant regulatory or taxation bodies.
>
> Enbridge Gas will also record 100% of the revenue requirement impact of any tax rates, rules, or credits (or similar mechanisms), specifically directed at energy transition activities. The determination of the appropriate sharing of any such impacts, between ratepayers and the Company, will be determined at the time of disposition.[1]

2. Further, in its letter dated May 6, 2026[2], the OEB stated that it: expects Utilities to continue to adhere to the OEB's July 25, 2019 accounting direction and continue to use the applicable CCA-related sub-account to address the revenue requirement impacts of the Re-Accelerated Investment Incentive (RII) and of any future CAA rule changes.

3. On March 26, 2026, Bill C-15 (Budget 2025 Implementation Act, No. 1) received Royal Assent and is now enacted legislation. Among other measures, Bill C-15 legislates the RII, which reinstates and expands accelerated CCA deductions for eligible depreciable property:

[1] EB-2022-0200, Rate Order, Appendix C, p.33.
[2] Accounting and Rates Direction Regarding Bill C-15 for the Reaccelerated Investment Incentive for Capital Cost Allowance, May 6, 2026.

- suspension of the CCA half year rule (property acquired after December 31, 2024 and available for use before January 1, 2034); and
- enhanced first year CCA deductions relative to “normal” depreciation (property acquired after December 31, 2024 and available for use before January 1, 2030);

4. These measures accelerate the timing of CCA deductions but do not change the total lifetime amount of depreciation deductible for tax purposes. As such, they constitute temporary timing differences and not permanent tax savings.

5. For the 2025 taxation year, Enbridge Gas placed qualifying capital assets into service that meet the legislated requirements for RII treatment. As a result:
   - the Company’s current income tax payable for 2025 was lower than would have been the case under the CCA rules assumed in rates;
   - the difference arises solely from accelerated tax depreciation, with an offsetting reduction in CCA deductions in future years; and
   - the impact is therefore temporary and fully reversible over the remaining lives of the assets.

<u>1. Modified CCA treatment under RII:</u>

6. For property that qualifies as RII, the legislation introduces two coordinated changes relative to the calculation of CCA, exclusive of any accelerated investment incentives:
   - <u>Suspension of the half year rule</u>

     RII property is not subject to the half year rule. Consequently, 100% of the capital cost of qualifying additions is included in the CCA base in the year the property becomes available for use. Note, the suspension of the half year rule

is consistent with Phase-out provision/incentive of Bill C-97 currently reflected in rates.

- Enhanced first year CCA allowance
  The prescribed CCA rate applicable to the relevant class is multiplied by an enhanced factor. For property placed in service before the end of the full enhancement period, this results in a first year CCA deduction equal to three times the normal first year CCA that would otherwise have been available for property subject to the half year rule.

Together, these two adjustments accelerate depreciation into earlier years while leaving the total lifetime CCA unchanged.

7. The incremental CCA attributable to RII in a given year is calculated as the difference between:
   - the enhanced CCA permitted under RII; and
   - the CCA amount that would have been deductible under the tax rules assumed in rates;
   - The income tax impact of the variance between the two is then determined and grossed up for taxes to determine the annual revenue requirement impact.

   This incremental amount represents a pure timing difference. The increase in first year CCA is fully offset by correspondingly lower CCA deductions in subsequent years.

8. Consistent with OEB direction, Enbridge Gas has recorded 100% of the incremental tax benefit arising from accelerated CCA to the TVDA. This results in a credit balance to ratepayers of $13.622 million, plus interest.

9. The details of the calculation can be found in Appendix 1.

Enbridge Gas
Calculation Of The Accelerated CCA Impact To Be Recorded In The Tax Variance Deferral Account

Line No.	Class	Particulars ($000s)	Opening UCC Accel. CCA	Opening UCC CCA in Rates	Total Additions Qualifying for Accel. CCA	Less: Lessor of Cost or Proceeds	Eligible CCA Additions	Accel. CCA Depreciable UCC Balance (1)	CCA in Rates Depreciable UCC Balance	Rate (%)	Accelerated CCA	CCA in Rates	Closing UCC Accel. CCA	Closing UCC CCA in Rates
		2025 Year-End	(a)	(b)	(c)	(d)	(e)	(f) = (e) x 1.5	(g) = (e) x 1	(h)	(i) = (f) x (h)	(j) = (g) x (h)	(k) = (a) + (e) - (i)	(l) = (b) + (e) - (j)
1	1	Buildings, structures and improvements, services, meters, mains	-	-	2,898.7	(4,922.1)	(2,023.3)	(3,035.0)	(2,023.3)	4%	(121.4)	(80.9)	(1,901.9)	(1,942.4)
2	1	Non-residential building acquired after March 19, 2007	-	-	48,028.8	-	48,028.8	72,043.3	48,028.8	6%	4,322.6	2,881.7	43,706.3	45,147.1
3	2	Mains acquired before 1988	-	-	-	-	-	-	-	6%	-	-	-	-
4	3	Buildings acquired before 1988	-	-	-	-	-	-	-	5%	-	-	-	-
5	6	Other buildings	-	-	-	-	-	-	-	10%	-	-	-	-
6	7	Compression equipment acquired after February 22, 2005	-	-	23,824.6	-	23,824.6	35,736.9	23,824.6	15%	5,360.5	3,573.7	18,464.1	20,250.9
7	8	Compression assets, office furniture, equipment	-	-	101,541.1	-	101,541.1	152,311.7	101,541.1	20%	30,462.3	20,308.2	71,078.8	81,232.9
8	10	Transportation, computer equipment	-	-	11,279.2	(753.0)	10,526.2	15,789.3	10,526.2	30%	4,736.8	3,157.9	5,789.4	7,368.4
9	12	Computer software, small tools	-	-	7,310.4	-	7,310.4	7,310.4	7,310.4	100%	7,310.4	7,310.4	-	-
10	13	Leasehold improvements	-	-	-	-	-	-	-	N/A	-	-	-	-
11	14.1	Intangibles	-	-	3,556.1	-	3,556.1	5,334.2	3,556.1	5%	266.7	177.8	3,289.4	3,378.3
12	14.1	Intangibles (pre 2017)	-	-	-	-	-	-	-	7%	-	-	-	-
13	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	-	-	8%	-	-	-	-
14	38	Heavy work equipment	-	-	3,709.6	(158.8)	3,550.8	5,326.3	3,550.8	30%	1,597.9	1,065.3	1,953.0	2,485.6
15	41	Storage assets	-	-	7,804.6	-	7,804.6	11,706.9	7,804.6	25%	2,926.7	1,951.1	4,877.9	5,853.4
16	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	-	-	45%	-	-	-	-
17	49	Transmission pipeline additions acquired after February 23, 2005	-	-	21,037.1	-	21,037.1	31,555.6	21,037.1	8%	2,524.4	1,683.0	18,512.6	19,354.1
18	50	Computers hardware acquired after March 18, 2007	-	-	10,052.2	-	10,052.2	15,078.2	10,052.2	55%	8,293.0	5,528.7	1,759.1	4,523.5
19	51	Distribution pipelines acquired after March 18, 2007	-	-	588,965.0	(394.9)	588,570.1	882,855.1	588,570.1	6%	52,971.3	35,314.2	535,598.8	553,255.9
20		Total	$ -	-	830,007.5	(6,228.7)	823,778.8	1,232,013.0	823,778.8		$ 120,651.4	82,871.1	703,127.4	740,907.7

	2025
CCA Variance (i) - (j)	37,780.3
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	10,011.8
Earnings Impact Grossed-up for Taxes Recorded in the TVDA (Earnings impact of Accelerated CCA grossed up at 0.735)	13,621.5

Notes:
(1) Equals 1.5x of the Eligible CCA Additions in Column (e), except Class 12, which is 1.0x of Column (e) amount since Class 12 has a CCA rate of 100%.

ACCOUNT NO. 179-323 DAWN PARKWAY SURPLUS CAPACITY DEFERRAL ACCOUNT

1. As part of the 2024 Rebasing Phase 1 Settlement Agreement, parties agreed to, and the OEB approved[1], the establishment of the Dawn Parkway Surplus Capacity Deferral Account. This account records the actual revenue from the sale of all or a portion of the 89 TJ/d Dawn Parkway System surplus capacity forecast. Dawn Parkway System surplus capacity used to reduce the Parkway Delivery Obligation (PDO) is not considered a sale of surplus capacity and reduces the 89 TJ/d Dawn Parkway System surplus capacity for purposes of determining actual revenue for this account.

2. In 2025, Enbridge Gas recognized $2.3 million of revenue from the sale of surplus capacity. Details of the sale of surplus capacity are provided in Table 1. In 2025, Enbridge Gas issued an operational notice informing shippers of a pressure restriction on the NPS 26 Trafalgar pipeline. That restriction will remain in effect until further notice and eliminates the ability to sell incremental Dawn Parkway capacity beyond the 51,098 GJ/day already contracted.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, pp.55-56.

Table 1
2025 Dawn Parkway Surplus Capacity

Line No.	Particulars	Volume (GJ/d)	Unit Rate ($/GJ)	Revenue ($000s)
		(a)	(b)	(c) = (a x b)
1	January	35,696	4.098	146.3
2	February	35,696	4.098	146.3
3	March	35,696	4.098	146.3
4	April	35,696	4.098	146.3
5	May	51,098	4.098	209.4
6	June	51,098	4.098	209.4
7	July	51,098	4.098	209.4
8	August	51,098	4.098	209.4
9	September	51,098	4.098	209.4
10	October	51,098	4.098	209.4
11	November	51,098	4.098	209.4
12	December	51,098	4.098	209.4
13	Total			2,260.3

ACCOUNT NO. 179-326 DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM VARIANCE ACCOUNT

1. On August 17, 2023, the OEB approved the 2024 Rebasing Phase 1 Settlement Agreement[1]. As part of the Settlement Agreement, the Parties agreed to the establishment of a new variance account for Distribution Integrity Management Program (DIMP) and Enhanced Distribution Integrity Management Program (EDIMP) costs. The new variance account is referred to as the DIMP Variance Account (DIMPVA). Parties also agreed to the filing of DIMP and EDIMP Annual Reports (at Exhibit G, Schedule 4, Tab 1), which provide evidence of the customer benefits achieved through DIMP and EDIMP activities..

2. The purpose of the DIMPVA is to track the variance between Enbridge Gas's spending each year on the DIMP and EDIMP programs and the costs included in rates. Parties agreed that $12.5 million is included in the 2024 O&M budget for these programs, and that variances from this $12.5 million will be recovered from or credited to ratepayers on an annual basis from 2024 until Enbridge Gas's next rebasing[2].

3. For 2025 Enbridge Gas escalated the base comparator from 2024 to $12.976 million incorporating PCI plus growth factors[3]. The balance of the 2025 DIMPVA that is being requested for clearance within this proceeding is a debit of $0.213 million, plus interest.

4. In terms of detailing out the budget, the 2024 DIMP and EDIMP workplan originally submitted as part of the EB-2025-0155 proceeding[4] is not the most current or

[1] EB-2022-0200, Settlement Agreement, August 17, 2023.
[2] EB-2022-0200, Settlement Agreement, August 17, 2023, Exhibit O1, Tab 1, Schedule 1, p.31.
[3] 2024 Base Rate Locate Budget ($12.5 million) x Inflation plus Growth factor ((1+(3.33% + 0.48%)) = 1.0381)
[4] EB-2025-0155, Exhibit C, Tab 2, Schedule 13, p. 2, Table 1

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). Enbridge Gas refined and updated the categorization of the 2024 DIMP and EDIMP costs as planning progressed and resource requirements became better understood. While the overall budget amount remained unchanged, the composition of costs within the budget was refined to reflect a more accurate understanding of the resources required to deliver the planned work.

5. In particular, under the original workplan, which was primarily developed to estimate the costs associated with individual 2024 DIMP and EDIMP objectives, costs for Internal Integrity Resources not solely dedicated to DIMP and EDIMP programs were included within the Project cost category. As the budget was refined and resource requirements became better understood, these costs were recategorized to the Administrative cost category to align with the established cost-tracking methodology used by the Integrity team. Under this approach, Internal Integrity Resource costs are tracked at the program level (e.g., DIMP, EDIMP, or other Integrity programs) rather than to individual projects.

6. As noted in the Administrative Costs section below, the categorization of these costs within the Administrative category is not indicative of these costs being of an overhead or indirect support nature, as many of these resources perform technical activities that directly contribute to the planning, assessment, prioritization, and execution of DIMP and EDIMP work. Table 1 illustrates this refinement in the budget categorization by showing the transfer of these costs from the Project category to the Administrative category.

Table 1
2024 DIMPVA Budget Recategorization

Line No.	Description	2024 Workplan ($ millions)	2024 Budget ($ millions)	Variance ($ millions)
1	DIMP Admin	0.699	1.556	0.857
2	EDIMP Admin	1.053	0.989	(0.064)
3	Total Admin	1.752	2.545	0.793
4	DIMP Projects	1.754	1.448	(0.306)
5	EDIMP Projects	8.995	8.507	(0.488)
6	Total Projects	10.749	9.955	(0.793)
7	Total DIMPVA	12.500	12.500	0

7. This updated budget breakdown represents Enbridge Gas's view of the expected distribution of DIMP and EDIMP expenditures and provides a more appropriate basis for comparison against actual results.

8. The finalized budget breakdown for the DIMP and EDIMP costs was previously filed with the OEB in July 2024 in response to a Consumers Council of Canada interrogatory in Phase 2 of the 2024 Rebasing Application.[5] This refined and updated budget breakdown formed the basis for development of the 2025 DIMP/EDIMP budget.

9. Table 2 provides a breakdown of the 2025 DIMP and EDIMP expenditures and variances against budget. Descriptions of the work types and significant contributing factors to the variances within each work type are described below.

[5] EB-2024-0111, Exhibit I.1.17-CCC-35, p.2, Table 1

Table 2
2025 DIMPVA Breakdown

Line No.	Description	2025 Escalated Budget ($ millions)	2025 Actuals ($ millions)	Variance ($ millions)
	DIMP Admin (Internal Integrity Resources)			
1	Admin	1.615	1.561	(0.055)
	DIMP Projects (External Integrity Resources)			
2	Investigations & Assessments	0.326	0.579	0.253
3	Pipe Inspections	0.379	0.271	(0.108)
4	Station Inspections	0.093	0.106	0.012
5	Regulator Set Inspections	0.647	0.870	0.224
6	DIMP Carryovers	0.058	0.007	(0.051)
7	Total DIMP	3.118	3.394	0.276
	EDIMP Admin (Internal Integrity Resources)			
8	Admin	1.027	0.946	(0.081)
	EDIMP Projects (External Integrity Resources)			
9	In-line Inspection (ILI)	7.937	7.818	(0.119)
10	Corrosion Survey	0.471	0.380	(0.091)
11	Digs (Validation)	0.276	0.423	0.147
12	Assessments & Consulting	0.147	0.233	0.086
13	EDIMP Carryovers	0.000	(0.004)	(0.004)
14	Total EDIMP	9.858	9.795	(0.063)
15	Total DIMPVA	12.976	13.189	0.213

1. Administrative Costs

10. In its EB-2025-0155, Decision and Order, the OEB expressed concerns regarding the level of Administrative costs recorded for the DIMP and EDIMP programs.

11. The OEB concluded that *"…the allocation of administrative costs is excessive…[and] is not persuaded by Enbridge Gas's explanation that the variance is attributed to budget reclassification…"*[6]

12. Enbridge Gas would like to clarify that the Administrative category is not solely comprised of overhead or indirect support functions. It also includes substantial technical engineering and integrity management work that directly enables DIMP and EDIMP outcomes.

13. Administrative costs reflect the delivery of technical work through Internal Integrity Resources instead of external contractors. If the same activities were completed by external consultants, these costs would be reported as Project costs despite producing the same technical outputs and integrity outcomes.

14. Table 3 provides a breakdown of Administrative costs for the DIMP and EDIMP programs, split into the following categories: Internal Integrity Resource costs, Oversight / Administrative costs and Other Administrative costs.

[6] EB-2025-0155, Decision and Order, June 25, 2026, p.14.

Table 3
2025 Administrative Cost Breakdown

Description	Internal Integrity Resource Costs ($ millions)	Oversight / Administrative Costs ($ millions)	Other Admin Costs ($ millions)	Total Admin Costs ($ millions)
DIMP Admin	1.122	0.391	0.047	1.561
EDIMP Admin	0.568	0.352	0.025	0.946
Total DIMPVA Admin	1.690	0.744	0.073	2.506

15. Oversight / Administrative Costs reflect the supervisory and management resources required to provide technical oversight, direction, and governance of the work performed by individual contributors.

16. The Other Administrative Costs category captures non-labour administrative expenditures, including travel and accommodation (T&A), training, professional dues, and any other materials or supplies required to enable the DIMP and EDIMP portfolios.

17. Internal Integrity Resource Costs consist of full-time employee (FTE) and contingent worker (CWR) labour. The resources in this category include professional engineers and engineers-in-training who perform technical work that directly enables the delivery of DIMP and EDIMP program objectives.

18. Examples of project-related activities performed by these Internal Integrity Resources include:
    - Risk and reliability modeling, including ongoing model enhancements and refinements;
    - Risk-informed prioritization of asset inspections, assessments, and remediation activities;

- Development and management of inspection and assessment scopes;
- Execution and support of integrity management projects;
- Technical review and analysis of inspection and assessment results; and
- Determination of mitigation requirements, remediation planning, and integrity management recommendations.

19. These activities are essential components of DIMP and EDIMP program delivery and are directly tied to integrity outcomes, risk reduction, and rate payer benefits.

1.1 Classification of Internal Integrity Resources as Administrative vs Projects Costs

20. Internal Integrity FTE and CWR resources often work on multiple integrity projects and activities simultaneously. Enbridge Gas manages and tracks these labour costs at a program level (DIMP vs. EDIMP) rather than at a project level and has therefore presented these costs as Administrative costs.

21. In contrast, DIMP and EDIMP Project costs consist of payments to external service providers and project execution resources that are not part of Enbridge's Integrity team (e.g. operations, construction, etc.). These expenditures can be reported at the project level.

22. However, in situations where it is determined that certain activities can be delivered more efficiently using incremental Internal Integrity Resources, as compared to external service providers, costs may be incurred and captured as part of the Administrative cost category to facilitate the work instead of the Project cost category. Although costs are shifted from the Projects category in these instances, the DIMP and EDIMP programs continue to deliver the intended program outcomes. Consequently, the relative proportion of Administrative and Project costs should not be interpreted as evidence of increased overhead or diminished customer value.

Rather, they reflect prudent management decisions that optimize the use of internal expertise, reduce overall program costs, and maximize value delivered to rate payers while maintaining the integrity objectives of the DIMP and EDIMP programs.

23. For example, Quantitative Risk Assessments (QRA) conducted on EDIMP pipelines are completed by internal technical staff whose costs are recorded within the Administrative category. These assessments directly enable integrity management decision-making and risk mitigation efforts. The effectiveness of these activities is illustrated in the DIMP/EDIMP Annual Report[7], which outlines capital cost avoidances of approximately $77.1 million, $34.3 million, and $5.4 million associated with the NPS 12 Wilson Avenue, NPS 12 Martin Grove, and NPS 8 St. Thomas pipelines, respectively.

24. The 2025 escalated budget for DIMP and EDIMP administrative costs was estimated at $2.642 million. Actual spend was $2.506 million for a variance of ($0.136 million). The variance is primarily due to staff vacancies.

2. DIMP Projects

25. DIMP Projects consists of five distinct work categories: Investigations & Assessments; Pipe Inspections; Station Inspections; Regulator Set Inspections; and DIMP Carryovers. The 2025 escalated budget for DIMP Projects was estimated at $1.503 million and actual spend was $1.833 million for a variance of $0.330 million.

26. The Investigations and Assessments work cost $0.579 million to complete, and the $0.253 million variance to the budget was primarily driven by investigations of heavier hydrocarbon contamination of polyethylene (PE) pipe and a plastic pipe records review.

[7] Exhibit G, Tab 4, Schedule 1.

27. The Pipe Inspections work focused on isolated steel services and steel riser inspections. Isolated steel service lines and steel risers that have the potential to be electrically disconnected from a cathodically protected steel pipeline system have a higher likelihood of leaks from corrosion. The total variance for this category was ($0.108 million).

28. The Station Inspections plan focused on identifying potential hazards at distribution stations, with a focus on the cathodic protection of below ground piping at the station. This work accounted for a variance of $0.012 million.

29. Regulator Set Inspections focused on service extensions, local and remote first cut regulator sets, greater than 400 series regulator sets, 200 & 400 series regulator sets, and bulk meters. This work category resulted in a variance of $0.224 million.

30. Forecast 2024 DIMP Carryover costs reflected estimated work performed but not accrued in 2024. Only $0.007 million of the escalated budgeted amount of $0.058 million DIMP carryover costs materialized in 2025, resulting in a variance of ($0.051 million).

3. EDIMP Projects

31. EDIMP Projects consists of five distinct work categories: In-line Inspection (ILI); Corrosion Survey; Digs (Validation); Assessments & Consulting; and EDIMP Carryovers. The 2025 escalated budget for EDIMP Projects was estimated at $8.831 million and actual spend was $8.849 million for a variance of $0.018 million.

32. The 2025 ILI budget mainly consisted of in-line pipeline inspections. The Digs work category involved mitigating/repairing any Phase 1 (immediate response) anomalies that were discovered as part of the ILI work. The ILI work category had a variance of ($0.119 million), which was offset by the Digs variance of $0.147 million for a

combined variance of $0.028 million. The total variance was driven by higher integrity dig costs, which was partially offset by three cancelled ILI runs on the NPS 20 Queensway pipeline.

33. The Corrosion Survey work category included above-ground surveys such as Cathodic Protection (CP) system surveys and non-intrusive pipeline assessments (NIPA). This work category had a variance of ($0.091 million) which was driven by lower costs on CP surveys, and was partially offset by higher costs due to challenges and uncertainties around NIPA surveys.

34. The Assessments & Consulting work category was used to hire a consultant to perform a desktop study to produce an inventory of geotechnical and hydrotechnical areas of concern. A total of eight pipelines were assessed along with an investigation into QRA model development. This work category had a variance of $0.086 million. The higher costs were due to some geohazard sites needing detailed investigation and field assessments, as well as the inclusion of the QRA model development project within this category.

35. Forecasted 2024 EDIMP Carryover costs would generally include expected residual costs for EDIMP projects commenced in 2024 but not concluded until 2025.

4. DIMP/EDIMP Annual Reporting

36. As part of the Settlement Agreement, Enbridge Gas also agreed to provide annual reporting on DIMP and EDIMP actual costs, setting out the work done (and associated costs), listing the projects/facilities where work was done, describing what facilities work was deferred or avoided or otherwise impacted as a result and discussing the cost/benefit analysis of the DIMP and EDIMP work done during the past year.[8]

[8] EB-2022-0200, Settlement Agreement, August 17, 2023, Exhibit O1, Tab 1, Schedule 1, p.56.

37. The DIMP/EDIMP Annual Report provides evidence of the customer benefits achieved through DIMP and EDIMP activities, including field inspections, integrity and risk assessments, remediation activities and repairs, and long-term mitigation strategies that support the safe and reliable operation of the distribution system. 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. The DIMP/EDIMP Annual Report is included at Exhibit G, Tab 4, Schedule 1.

ACCOUNT NO. 179-328 POST RETIREMENT TRUE-UP VARIANCE ACCOUNT

1. As part of the 2024 Rebasing Phase 1 Settlement Agreement, parties agreed to, and the OEB approved, the establishment of the Post-Retirement True-Up Variance Account (PTUVA).[1] This account records the difference, in excess of a $10 million deadband (debit or credit), between the revenue requirement impact of actual pension and other post-employment benefits (OPEB) costs (accrual and cash-based amounts) and the revenue requirement impact of pension and OPEB costs (accrual and cash-based amounts) included in rates.

2. The OEB-approved forecast revenue requirement impact of pension and OPEB costs (accrual and cash-based amounts) embedded in rates for 2025 is a credit of $8.6 million[2]. For the year ended December 31, 2025, the actual revenue requirement impact that resulted from pension and OPEB costs (accrual and cash-based amounts) was a credit of $67.6 million. The 2025 PTUVA balance, which represents the difference between the OEB-approved forecast and actual revenue requirement impact of pension and OPEB costs in excess of the agreed upon $10 million deadband, is a credit to ratepayers of $49.0 million, plus interest. A breakdown of the forecast and actual revenue requirement as well as the derivation of the $49.0 million PTUVA balance is provided at Attachment 1.

3. The variance between the OEB-approved forecast and the actual revenue requirement impact of pension and OPEB costs is primarily due to a higher actual return on plan assets versus the return forecast as part of the cost reflected in rates.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, p.56.
[2] Escalation of $8.3M base 2024 amount equals base x PCI + Growth factor for 2025: $8.3M x ((1+(3.33%+0.48%)) = $8.6M.

2025 Pension True-Up Variance Account (PTUVA)

Line No.	Particulars ($ millions)	Actual 2025 (a)	OEB Approved[1] 2025 (b)	Variance (a) - (b)
	Incremental Operating Expenses:			
1	Operating and Maintenance Expenses	(46.5)	(1.7)	(44.8)
2	Depreciation Expense	-	-	-
3	Property Taxes	-	-	-
4	Total Incremental Operating Expenses	(46.5)	(1.7)	(44.8)
	Incremental Income Taxes:			
5	Income (Loss) before Income Taxes	46.5	1.7	44.8
6	Utility/Tax Timing Difference:			
7	Add-back: Accruals	(46.5)	(1.7)	(44.8)
8	Deduct: Cash Contributions	(12.1)	(17.5)	5.4
9	Taxable Income (Loss)	(12.1)	(17.5)	5.4
10	Income Taxes Payable (Benefit) (line 16 * 26.5% Tax Rate)	(3.2)	(4.6)	1.4
11	Net Revenue Deficiency (Sufficiency) (line 11 + line 17)	(49.7)	(6.3)	(43.4)
12	Grossed-up Revenue Requirement (line 18 / (1-0.265))	(67.6)	(8.6)	(59.0)
13	Deferral Deadband +/- $10M			(10.0)
14	Total PTUVA Deferral Receivable (Payable) (line 19 - line 20)			(49.0)

Notes:

1) Escalation of base 2024 base amounts in lines 1 & 8 = base amount x PCI + Growth factor (1.0381)

ACCOUNT NO. 179-330 CLEAN FUEL REGULATION CREDITS DEFERRAL ACCOUNT

1. On August 17, 2023, the OEB issued its Decision on the 2024 Rebasing Phase 1[1] Settlement Agreement. The Decision approved the establishment of a new deferral account to record revenues and incremental costs associated with the Federal Clean Fuel Regulation (CFR)[2]. The new deferral account is referred to as the CFR Credits Deferral Account.

2. The purpose of the CFR Credits Deferral Account is to record the revenues obtained by Enbridge Gas from the sale of CFR credits, net of any incremental offsetting credit formation, certification and transaction administration costs. These administration costs could include incremental staffing costs, consulting costs, legal costs, and other costs such as training, conferences and market monitoring subscriptions.

3. The objective of the CFR is to reduce the carbon intensity of liquid fuels produced and imported into Canada. Entities subject to the CFR satisfy their obligations through the submission of CFR credits to the Government of Canada. CFR credits can be created through three main categories of credit-creating actions:

    1. Actions that reduce the carbon intensity of liquid fossil fuels throughout their lifecycle,
    2. Supplying low-carbon fuels in Canada, and
    3. Supplying fuel and energy in advanced vehicle technologies.

4. As a gaseous fuel supplier, Enbridge Gas does not have an obligation under the CFR; however, Enbridge Gas is able to participate in the CFR on a voluntary basis.

[1] EB-2022-0200.
[2] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, pp.56-57.

Enbridge Gas is registered under the CFR as a Registered Creator and can create credits through end-use fuel switching in vehicles, an eligible credit creation activity.

5. In 2025, Enbridge Gas created credits under the CFR from its compressed natural gas (CNG) vehicle activities during the 2024 compliance period. Enbridge Gas sold the credits in 2025 and recorded the revenue from the sale in the CFR Credits Deferral Account, as a payable of $0.035 million, plus interest.

ACCOUNT NO. 179-331 INDIGENOUS WORKING GROUP DEFERRAL ACCOUNT

1. The purpose of the Indigenous Working Group (IWG) Deferral Account is to record incremental capacity funding amounts associated with the IWG as described in and established pursuant to Issue 4 in the 2024 Rebasing Phase 1 Settlement Agreement.[1]

2. During 2025, the IWG met in person at the Enbridge Gas Toronto office on May 14, and September 23. The IWG also met virtually on July 15 and November 26, 2025. In 2025, the IWG's key initiatives were to advance reconciliation-related dialogue (including discussion of reconciliation principles and the updated IRAP), improve Enbridge Gas processes affecting Indigenous communities (particularly the LTC environmental/archaeology processes), and begin structured engagement planning for upcoming major filings and programs (including 2029 rebasing and related planning work). The IWG Annual Report found at Exhibit G, Tab 3, Schedule 1, sets out more details on the activities of the IWG for 2025.

3. The balance in the IWG Deferral Account for 2025 is a debit of $0.269 million plus interest. Table 1 outlines the amounts paid in 2025, by IWG participant.

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.18.

Table 1
IWG Incremental Capacity Funding - 2025

Line No.	Participant	Amount ($000s)
1	The Brattle Group Canada ULC	124.2
2	Resilient LLP	79.7
3	Woodward and Co	38.9
4	Three Fires Group	12.5
5	Mississaugas of Scugog Island First Nation	9.0
6	Chippewas of the Thames First Nations	4.3
7	Total	$ 268.6

ACCOUNT NO. 179-333 AVERAGE USE VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2025 Average Use Variance Account (AUVA)[1] balance. This account applies to all general service rate classes of Enbridge Gas, specifically, Rate 1, Rate 6, Rate M1, Rate M2, Rate 01 and Rate 10.

2. The AUVA records the revenue impact, exclusive of gas costs, of the volumetric difference between the actual weather-normalized average use experienced during the year and the forecast average use per customer embedded in OEB-approved rates for general service customers in Rate 1, Rate 6, Rate M1, Rate M2, Rate 01 and Rate 10[2].

3. The 2025 actual average use is weather normalized using 2025 forecasted heating degree days (HDD) which were produced using the same methodologies that underpin the 2024 OEB-approved volumetric forecast.

4. For Rate 1, the 2025 actual weather-normalized average use was 2.5% lower than the 2025 forecast, resulting in a total debit[3] from ratepayers of $12.1 million, plus interest.

5. For Rate 6, the 2025 actual weather-normalized average use was 1.6% higher than the 2025 forecasted average use, resulting in a total credit to ratepayers of $4.9 million, plus interest.

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[1] EB-2022-0200, OEB Decision and Order, December 21, 2023, Section 5.5.1, p.121.
[2] EB-2024-0111, OEB Decision on Settlement and Interim Rate Order, November 29, 2024, Appendix C.
[3] A credit in the AUVA deferral account indicates a refund to ratepayers and a debit indicates a collection from ratepayers.

6. For Rate M1, the 2025 actual weather-normalized average use was 4.2% lower than the 2025 forecasted average use, resulting in a total debit from ratepayers of $9.2 million, plus interest.

7. For Rate M2, the 2025 actual weather-normalized average use was 11.2% lower than the 2025 forecasted average use, resulting in a total debit from ratepayers of $9.9 million, plus interest.

8. For Rate 01, the 2025 actual weather-normalized average use was 3.3% lower than the 2025 forecasted average use, resulting in a total debit from ratepayers of $4.4 million, plus interest.

9. For Rate 10, the 2025 actual weather-normalized average use was 12.9% lower than the 2025 forecasted average use, resulting in a total debit from ratepayers of $3.9 million, plus interest.

10. Based on 2025 actual results, Rate 1, Rate M1, Rate M2, Rate 01, and Rate 10 experienced declines that were steeper than historical trends, resulting in variances higher than those observed historically. Rate 6 on the other hand represents a relatively modest variance.

11. The 2025 forecast average use was developed using actuals up to 2023 and assumed historical trends would continue. Enbridge Gas will continue to monitor the recent changes in average use trends for the affected rate classes as additional actual data becomes available.

12. Attachment 1 details the calculation of the 2025 AUVA by rate class that results in a net debit from ratepayers of $34.5 million, plus interest.

Enbridge Gas
Average Use Variance Account (AUVA) (1)
Account No. 179-333

Line No.	Particulars	Unit of Measurement	Rate 1	Rate 6	Rate M1	Rate M2	Rate 01	Rate 10	Net Account Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Forecast Average Use	(m^3)	2,310	27,236	2,649	151,411	2,710	139,738	
2	Actual Normalized Average Use	(m^3)	2,252	27,659	2,538	134,418	2,619	121,726	
3	Average Use Variance (Line No. 1 minus Line No. 2)	(m^3)	58	(423)	111	16,994	91	18,012	
4	2024 OEB-approved average number of customers (2)	(#)	2,163,088	172,974	1,204,177	8,077	369,594	2,204	
5	Normalized Volumetric Variance (Line No. 3 multiplied by Line No.4)	(10^6m^3)	126.3	(73.1)	133.9	137.3	33.5	39.7	
6	Net Annual Weighted Average Unit Rate (3)	($/m^3$)	$0.095692	$0.066792	$0.068405	$0.071866	$0.131001	$0.097914	
7	Annual AUVA Balance Amount (Line No. 5 multiplied by Line No. 6) (4)	($ millions)	$12.1	($4.9)	$9.2	$9.9	$4.4	$3.9	$34.5

Notes:

(1) Harmonized Average Use Variance Account (AUVA) as per EB-2022-0200 Decision and Order, Section 5.5.1. Reference to 'normalized' in Table 1 implies weather normalization based on 2025 Forecast Heating Degree Days (HDD).

(2) Refers to 2024 OEB-approved annual average number of customers including adjustment for customer numbers agreed to in the 2024 Rebasing Phase 1 Settlement Proposal (EB-2022-0200).

(3) Represents the volume-weighted average of OEB-approved monthly unit rates in effect.

(4) (+) value reflects a debit (collection) from ratepayers and refund to Enbridge Gas which results when forecasted average use is higher than the actual normalized average use.
(-) value reflects a credit (refund) to ratepayers and collectable from Enbridge Gas which results when the forecasted average use is lower than the actual normalized average use.

ACCOUNT NO. 179-335 – GETTING ONTARIO CONNECTED ACT VARIANCE ACCOUNT

1. Establishment of the Getting Ontario Connected Act (GOCA) Variance Account was approved by the Ontario Energy Board (OEB) in the Request for Generic Variance Account Decision.[1]. The purpose of the GOCA Variance Account is to track incremental pipeline locate costs resulting from the enactment of Bill 93 on April 14, 2022. Bill 93 included amendments to the Ontario *Underground Notification System Act, 2012*[2] and the *Building Broadband Faster Act, 2021*[3]. The GOCA Variance Account is intended to continue for each year of the current IR term (2024 to 2028).

2. In the Request for Generic Variance Account Decision[4], the OEB issued an accounting order for gas utilities to establish the GOCA Variance Account to record the variance between locate costs resulting from Bill 93 and the approved cost included in base rates. According to the OEB:

> This account includes costs incurred to enable the locate activities. Utilities are expected to track costs at a sufficiently detailed level to assist in a review of the costs incurred, materiality, and causation related to Bill 93 at the time of disposition. Specifically, utilities are to demonstrate that recorded amounts in their accounts are both incremental to the base rates and are a direct result of Bill 93.[5]

   Enbridge Gas has recorded in the GOCA, the incremental 2025 locating costs, in excess of the 2025 budget, that are directly attributable to the impacts of Bill 93.

3. The balance of the 2025 GOCA Variance Account that is being requested for clearance is a debit of $14.093 million, plus interest. The background and methodology employed on arriving at this amount are outlined in detail below.

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[1] EB-2023-0143, Decision and Order, October 31, 2023.
[2] Bill 8, Ontario Underground Infrastructure Notification System Act, 2012, June 19, 2012. https://www.ola.org/en/legislative-business/bills/parliament-40/session-1/bill-8
3 Bill 257, Supporting Broadband and Infrastructure Expansion Act, April 12, 2021 https://www.ola.org/en/legislative-business/bills/parliament-42/session-1/bill-257
[4] EB-2023-0143, Decision and Order, October 31, 2023.
[5] EB-2023-0143, Decision and Order, Schedule B, October 31, 2023.

4. Enbridge Gas's unit cost for locating was ~ $32 in 2021 based on actuals prior to the enactment of Bill 93. Post enactment, locate unit costs increased by over 100%. The increase in cost was a direct result of Bill 93 which imposed a five-business-day deadline for completing standard locate requests and introduced absolute liability including administrative penalties for infrastructure owners failing to comply. Bill 93 has resulted in incremental locating costs to meet this compliance mandate that are not covered by current rates. This evidence outlines the drivers behind Bill 93 cost increases as well as the incremental cost calculations for 2025.

Table 1
2019-2025 External Locate Costs

Line No.	Particulars	2019	2020	2021	2022	2023	2024	2025
1	Total Locates (millions)	1.1	1.01	1.07	1.02	0.98	0.99	0.94
2	Total External Costs for Locate Delivery ($ millions)	$38.4	$33.5	$34.5	$39.9	$65.8	$66.0	$67.2
3	Average Cost per Locate ($ dollars)	$35	$33	$32	$39	$67	$67	$71

5. During Phase 1 of the 2024 Rebasing Application, Enbridge Gas acknowledged that the approved 2024 locate budget would not fully capture the incremental costs associated with Bill 93, given the considerable uncertainty of its full impacts at the time.[6] To address this, Enbridge Gas proposed the creation of a variance account to record differences between actual external locating costs and the approved 2024 budget.[7] Enbridge Gas withdrew its variance account request when the OEB initiated the generic proceeding which established the GOCA Variance Account. The 2024 base budget, which was prepared in early to mid-2022, incorporated allowances for typical cost drivers—such as inflation, typical wage increases, and general market pressures—as well as an increase for anticipated, but then-unknown, Bill 93 related

[6] EB-2022-0200, Exhibit I.4.4-STAFF-122.
[7] EB-2022-0200, Exhibit 9, Tab 1, Schedule 3, pp.8-11.

impacts. The 2024 approved budget appropriately captured all foreseeable and controllable financial pressures at the time. For 2025, the budget in rates has been determined by escalating the 2024 approved budget by PCI and customer growth, which should generally account for typical inflationary increases in locating costs. The $14.093 million recorded is in excess of the 2025 budget in rates and is directly and solely attributable to structural changes in the locate industry driven by Bill 93.

1. Drivers Behind Bill 93 Cost Increases

6. Locate costs have increased due to the new legislated locate delivery timelines resulting from Bill 93 and the absolute liability introduced for non-compliance. Enbridge Gas's average locate delivery times were 13 days and 15 days in 2021 and 2022 respectively. Bill 93 legislates a 5 day locate delivery mandate which put tremendous stress on the locating industry. To meet the new legislated locate timelines, Locate Service Providers (LSP) were required to onboard a significant amount of new locators, as well as increase locator wages to attract and retain qualified talent under tight labour market conditions. LSPs renewed unionized labour contracts in 2022 and based on the new operating environment unionized wages increased significantly. The single utility locating rate paid by Enbridge Gas increased by 128% on average due to these renegotiated wage increases with various LiUNA locals. All these factors – driven by Bill 93 – led to a material increase in average external locating unit costs between 2023 and 2025. Enbridge Gas has included only incremental external locating costs in the variance account.

7. It is also important to consider that, effective May 1, 2024, Ontario Regulation 136/24 introduced a separate category of "specified locate requests" for large excavation or dig sites and prescribed a 10-business-day completion period for those requests, which are submitted to Ontario One Call as Advanced Requests. This change may affect the comparability of reported locate volumes in 2024 to 2025 and beyond for certain large-scale excavation activities, as work associated with multi-property or

corridor-type projects can now be reflected through a single specified request rather than multiple standard requests, which may reduce the number of recorded locates for this subset of work. However, this change does not necessarily reduce the underlying workload or total effort required to complete locate activities for that work. While the relationship between locate volumes and total cost is not linear, the consolidation of multiple individual locates into single locate requests will, in some cases, contribute to higher observed average cost per locate.

8. As outlined in Table 2, Enbridge Gas has cost reducing mechanisms in place aimed at reducing the ongoing external costs related to locating. Alternative Locate Agreements (ALAs), generating $10.4 million in locating cost avoidance in 2025, are contractual agreements between Enbridge Gas and other infrastructure owners that allow excavations to occur in certain circumstances without requiring an LSP to provide a locate. Enbridge Gas has also established a locate screening centre where locate requests are reviewed prior to being sent to LSPs. The screening centre has resulted in $1.7 million in locate savings in 2025. Approximately $6.5 million (the cost avoidance average from 2020 to 2022) was factored into the 2024 locating budget. The further increase in cost avoidance achieved in 2025 (~$5.6 million) reduced what otherwise would have been included in the deferral account balance.

Table 2
2020-2025 Estimated Locating Cost Avoidance

Line No.	Particulars ($ millions)	2020	2021	2022	2023	2024	2025
1	ALA	5.9	6.5	6.4	11.6	11.9	10.4
2	Locate Screening	0.1	0.3	0.3	0.6	1.0	1.7
3	Total Locating Cost Avoidance	6.0	6.8	6.7	12.2	12.8	12.1

9. Table 3 outlines the 2025 GOCA balance calculation.

Table 3
2025 Budget vs. Actuals

Line No.	Particulars ($ millions)	Amount
1	2025 Locate Budget[8]	53.1
2	2025 Locate Actuals	67.2
3	2025 GOCA Variance Balance	14.1

10. It should be noted that Enbridge Gas has not included any Vital Main Standby (VMS) costs in the 2025 GOCA balance. This is in keeping with the OEB's Decision for the 2023 GOCA balance[9].

[8] 2024 Base Rate Locate Budget ($51.1 million) x Inflation plus Growth factor ((1+(3.33% + 0.48%)) = 1.0381)
[9] EB-2024-0125, Decision and Order, September 23, 2025. As explained in evidence in 2024 (EB-2025-0155, Exhibit C, Tab 2, Schedule 18, pp.5-6), Enbridge Gas continues to assert that the VMS cost increases are directly related to Bill 93 and continue to represent a significant ongoing cost pressure.

ACCOUNT NO. 179-336 DISPOSITION OF PROPERTY DEFERRAL ACCOUNT

1. As part of the 2024 Rebasing Phase 1 Decision[1] the OEB ordered the establishment of the Disposition of Property Deferral Account (DPDA). This account records 50% of the grossed-up after-tax gain/loss resulting from the disposition of non-depreciable land. The after-tax gain/loss is calculated as the difference in proceeds (sale price net of any transaction costs) and the regulatory book value of the property, less applicable capital gain/loss taxes. 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.

2. 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.

3. For 2025 a total of 7 properties were sold in the following locations: Brampton, Dryden, Iroquois Falls, Nipigon, Ottawa, St. Thomas & Stratford. These sales resulted in a total grossed-up after-tax gain recorded in the DPDA of $12.804 million, plus interest. A detailed breakdown of how the DPDA balance is derived is provided in Attachment 1.

4. 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

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

evaluations provide an objective, market-based assessment of the relative value of land and building components.

5. Details of each property disposition are provided below:

   a) Brampton

      In August 2025, Enbridge Gas entered into an Agreement of Purchase and Sale for the property located at 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 for $53,410. The transaction represents a taking initiated by the Region of Peel for road allowance purposes.

   b) Dryden

      On May 8, 2025, Enbridge Gas closed the sale of the property located at 304 Kennedy Road, Dryden, Ontario, for proceeds of $209,000. The sale followed the completion and commissioning of a new Dryden operations facility, rendering the legacy property surplus to operational requirements.

   c) Iroquis Falls

      On November 27, 2025, Enbridge Gas entered into an Agreement of Purchase and Sale for the disposition of land in Iroquois Falls, Ontario, for proceeds of $54,886. The property had been acquired for future operational use; however, after funding for the associated capital project was removed from the Capital Plan, the municipality exercised its contractual buy-back right under the original Agreement of Purchase and Sale, as construction had not commenced within the stipulated timeframe.

d) Nipigon

On February 27, 2025, Enbridge Gas closed the sale of the property located at 2 Wadsworth Drive, Nipigon, Ontario, for proceeds of $200,000. The sale followed the consolidation of facilities, rendering the legacy property surplus to operational requirements.

e) Ottawa – Coventry Road

In January 2025 Enbridge Gas entered into an Amended Agreement of Purchase and Sale for the property located at 400 Coventry Road, Ottawa, Ontario for a final sales price of $20,000,000.

The Coventry Road and SMOC facilities were replaced with a single, right-sized operations site to address underutilization, eliminate overlapping service coverage, and improve operational efficiency and location access.

f) St. Thomas

On August 21, 2025, Enbridge Gas closed the sale of the property located at 25 Sparling Road, St. Thomas, Ontario, for proceeds of $1,600,000. The sale followed the consolidation of operational depot facilities, rendering the legacy property surplus to operational requirements.

g) Stratford

On September 15, 2025, Enbridge Gas closed the sale of the property located at 827 Erie Street, Stratford, Ontario, for proceeds of $2,000,000. The sale followed the consolidation of operational depot facilities, rendering the legacy property surplus to operational requirements.

Enbridge Gas
Summary of Property Dispositions
For the Year December 31, 2025

Line No.	Description	Reference	Brampton	Dryden	Iroquois Falls	Nipigon	Ottawa	St Thomas	Stratford	Total
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Sale Price		$ 53,410	$ 209,000	$ 54,886	$ 200,000	$ 20,000,000	$ 1,600,000	$ 2,000,000	$ 24,117,296
2	Closing Costs		$ -	$ 15,164	$ 5,024	$ 14,931	$ 265,248	$ 83,521	$ 103,274	$ 487,161
3	Net Proceeds	Line 1 - Line 2	$ 53,410	$ 193,836	$ 49,862	$ 185,069	$ 19,734,752	$ 1,516,479	$ 1,896,726	$ 23,630,134
4	Percentage of Sale Allocated to Land		100%	14%	100%	20%	100%	52%	68%	
5	Land Proceeds	Line 3 X Line 4	$ 53,410	$ 27,823	$ 49,862	$ 37,014	$ 19,734,752	$ 788,569	$ 1,289,774	$ 21,981,204
6	NBV of Land		$ 78,896	$ 6,435	$ 74,995	$ 900	$ 87,874	$ 13,219	$ 22,121	$ 284,441
7	Gain/(Loss) on Sale of Land	Line 5 - Line 6	$ (25,486)	$ 21,388	$ (25,133)	$ 36,114	$ 19,646,879	$ 775,350	$ 1,267,652	$ 21,696,763
8	Less: Capital Gains Tax	Line 7 X 50% X 26.5%	$ (3,377)	$ 2,834	$ (3,330)	$ 4,785	$ 2,603,211	$ 102,734	$ 167,964	$ 2,874,821
9			$ (22,110)	$ 18,554	$ (21,803)	$ 31,329	$ 17,043,667	$ 672,616	$ 1,099,688	$ 18,821,942
10	50% Ratepayer Portion	Line 9 X 50%	$ (11,055)	$ 9,277	$ (10,902)	$ 15,664	$ 8,521,834	$ 336,308	$ 549,844	$ 9,410,971
11	Gross-Up For Taxes	1 - 26.5%	73.5%	73.5%	73.5%	73.5%	73.5%	73.5%	73.5%	73.5%
12	Gross Amount Credited to Ratepayers	Line 10 / Line 11	$ (15,040)	$ 12,622	$ (14,832)	$ 21,312	$ 11,594,332	$ 457,562	$ 748,087	$ 12,804,042

ACCOUNT NO. 179-338 LEAP EMERGENCY FINANCIAL ASSISTANCE FUNDING DEFERRAL ACCOUNT

1. On February 12, 2024, the OEB announced changes to the Low-income Energy Assistance Program Emergency Financial Assistance (LEAP EFA)[1]. The OEB also included two deferral accounts, one each for the rate-regulated electricity and gas distributors to record prudently incurred LEAP EFA contributions that exceed the funding amounts embedded in rates.

2. As part of the 2024 Rebasing Phase 1 Interim Rate Order[2], the OEB approved the establishment of the Enbridge Gas LEAP EFA Funding Deferral Account, its purpose to record incremental LEAP EFA contributions made on or after March 1, 2024 (the effective date of the account), that are beyond the amount currently embedded in distribution rates.

3. 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.[3] Enbridge Gas contributed $4.7 million in total, which exceeded the base LEAP EFA funding requirement for 2025 of $3.5 million[4].

4. 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. As a result, Enbridge Gas has recorded the incremental $1.2 million, plus interest in the LEAP EFA Funding Deferral Account for 2025.

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[1] EB-2023-0135.
[2] EB-2022-0200, Interim Rate Order, April 11, 2024, Appendix C, p.58.
[3] EB-2008-0150, Report of the OEB, March 10, 2009, pp. 8-11.
[4] 0.12% of 2025 Delivery Revenue as approved in EB-2024-0111, Draft Rate Order, November 4, 2024, Working Papers, Schedule 3, column (h), line 29.

ACCOUNT NO. 179-340 OEB COST ASSESSMENT V/A

1. As part of the 2024 Rebasing Phase 2 Settlement Agreement[1], parties agreed to, and the OEB approved the establishment of the OEB Cost Assessment Variance Account (OEBVA). 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, subject to the following parameters. The $9.4 million threshold will be adjusted each year using the IRM formula. Each year, Enbridge Gas will be entitled to recover any amounts that are more than $2 million above the annual threshold amount. In any year where the actual OEB Cost Assessment amounts are below the annual threshold amount, Enbridge Gas will credit all amounts below the threshold to ratepayers. This account is effective January 1, 2025.

2. For 2025 the annual threshold is set at $9.758[2] million. Based on this threshold, the balance recorded in the OEBCA is a debit (or receivable) of $2.997 million plus interest. The details of the difference between the actual annual OEB cost assessment amounts for 2025 and the applicable annual threshold amount are set out in Table 1.

[1] EB-2024-0111, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, November 29, 2024, p.11.
[2] Escalation of $9.4M base 2024 amount equals base x PCI + Growth factor for 2025: $9.4M x ((1+(3.33%+0.48%)) = $9.758M.

Table 1
2025 OEB Cost Assessment Variance
($ millions)

Line No.	Period	OEB Cost Assessment
1	Q1	3.477
2	Q2	3.477
3	Q3	3.477
4	Q4	4.325
5	Total	14.755
6	OEB Approved	9.758
7	Variance	4.997
8	Threshold	2.000
9	Deferred Variance	2.997

ACCOUNT NO. 179-341 IRP SYSTEM PRUNING DEFERRAL ACCOUNT

1. On November 4, 2024, Enbridge Gas filed the Settlement Proposal for Enbridge Gas' Rebasing Phase 2, where parties agreed that a new Integrated Resource Planning (IRP) System Pruning Deferral Account with a $5 million cap would be created for recording incremental costs incurred to develop and implement one or two IRP system pruning pilot projects for later recovery.[1]

2. 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.

3. As noted in the evidence for this account in the 2024 Deferral and Variance Account Clearance Application[2], recovery of the 2024 amounts would be requested in a future application.

4. 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. [3] On July 4, 2025, Enbridge Gas filed its 2024 IRP Annual Report, with the System Pruning approach filed as Appendix G.[4] Enbridge Gas subsequently began pilot implementation. As the milestone conditions of the Settlement Proposal have been

[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, p.20.
[2] EB-2025-0155, Exhibit C, Tab 2, Schedule 20, p.9-10.
[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, p.19-20
[4] EB-2025-0064, Exhibit I.1.13-ED-4 Attachment 1, p.108.

met, Enbridge Gas is proposing to recover the balance in the IRP System Pruning Deferral Account related to System Pruning pilot costs incurred in 2024 and 2025.

1. 2024 Costs

5. The costs incurred include the following activities related to the System Pruning pilot:
    a) Jurisdictional Scan – costs associated with conducting a jurisdictional scan on system pruning activities. Enbridge Gas, in consultation with the IRP Technical Working Group (TWG), engaged Det Norske Veritas (DNV) Canada Ltd, where the study was conducted for, and on behalf of, Enbridge Gas, OEB staff, other members of the IRP TWG and, ultimately, all Enbridge ratepayers. The objective of the report is to provide a greater understanding and insight into how gas utilities are approaching pruning of their gas distribution pipelines. This report is intended to provide Enbridge Gas, the IRP TWG and the 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.

2. 2025 Costs

6. The costs incurred include the following activities related to the System Pruning pilot.
    a) Jurisdictional Scan – costs associated with conducting a jurisdictional scan on system pruning activities. The scan was completed on August 15, 2025.[5]
    b) Customer Research – costs associated with customer research to inform the development of the pilot approach. This included qualitative research (focus groups) and quantitative research (customer survey) to understand

[5] System Pruning Jurisdictional Scan, Enbridge Gas, August 15, 2025, (link).

engagement approaches, offer considerations, customer attitudes, and perceptions.

c) Customer Engagement – costs associated with the pre-screen outreach to customers for implementation of the pilot. This included informational material about the pilot and pre-screen form, sent via courier and email, for customers to express their interest level in participating in the pilot.

d) Incremental Staff – costs associated with 1 incremental position responsible for leading the pilot. This resource is incremental to the IRP roles that are in O&M base rates.

7. Table 1 provides the breakdown of these expenditures.

Table 1
Breakdown of Expenditures – System Pruning Pilot Costs

Line No.	Item	Description	Millions ($)
1	Jurisdictional Scan	Completion of scan	0.124
2	Customer Research	Qualitative and quantitative research	0.057
3	Customer Engagement	Pre-screen implementation	0.038
4	Incremental Staff	Salaries, loadings and expenses	0.146
5	Total		0.366

ACCOUNTS NOT BEING REQUESTED FOR CLEARANCE

1. The following 2025 accounts have no balance, and are therefore not requested for clearance to customers:

    - Unauthorized Overrun Non-Compliance Deferral Account
    - Incremental Capital Module Deferral Account
    - Expansion of Natural Gas Distribution Systems Variance Account
    - Green Button Initiative Deferral Account
    - Cloud Computing Implementation Costs Deferral Account
    - Asset Life Extension Costs Deferral Account
    - Enbridge Sustain Affiliate Recoveries Variance Account
    - Open Bill Extension Deferral Account

2. 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.

1. Account No. 179-304 Unauthorized Overrun Non-Compliance Deferral Account

3. With regard to the Unauthorized Overrun Non-Compliance Deferral Account, in its 2024 Rebasing Phase 1 Decision[1], the OEB approved harmonization of certain deferral accounts of EGD and Union. This included harmonization of the Unauthorized Overrun Non-Compliance Deferral Account. The purpose of the account is to record any unforecasted penalty revenue received from interruptible distribution customers who do not comply with a distribution interruption. In 2025,

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

there were 4 interruption events called in the EGD rate zone for a total of 183.9 days, and 5 interruption events called in the Union North rate zone for a total of 37.1 days. There were no interruption events called in the Union South rate zone. The EGD rate zone had 1 customer who failed to comply with their interruptions (2 events), resulting in approximately $0.05 million in non-compliance charges. In the absence of a harmonized gas supply plan in 2025, EGI continued to record the EGD RZ non-compliance charges in the Purchase Gas Variance Account – EGD Rate Zone. Until such time as the harmonized gas supply plan is implemented, EGI will continue with this process. All Union rate zone customers were able to comply with each interruption event, therefore incurring no non-compliance charges in 2025.

2. Account No. 179-344 Enbridge Sustain Affiliate Recoveries Variance Account

4. The purpose of the Enbridge Sustain Affiliate Recoveries Variance Account is to record, on an asymmetrical basis, any additional amounts above $1 million (as adjusted annually according to the IRM formula) paid or payable by Enbridge Sustain to Enbridge Gas for goods or services provided in each year of the 2024-2028 IRM term.

5. In the 2024 Rebasing Phase 2 Decision on Settlement Proposal and Interim Rate Order[2] the Parties agreed that Enbridge Gas will implement a $1 million base rate adjustment for 2024, to reflect amounts paid by Enbridge Sustain to Enbridge Gas for services received that have not been included in base rates. The Parties further agreed that a new asymmetrical Enbridge Sustain Affiliate Recoveries Variance Account will be created that will credit ratepayers with any additional amounts over $1 million paid or payable by Enbridge Sustain to Enbridge Gas for goods or services received each year of the 2024-2028 IRM term.[3]

[2] EB-2024-0111 Decision on Settlement Proposal and Interim Rate Order, November 29, 2024.
[3] EB-2024-0111 Decision on Settlement Proposal and Interim Rate Order, November 29, 2024, p.10.

6. During 2025, Enbridge Sustain received services at a total cost of $0.7 million. As such, when compared to an escalated base of $1.038 million[4], there is no balance recorded in the Enbridge Sustain Affiliate Recoveries Variance Account for 2025.

7. Table 1 defines the gross eligible costs paid or payable by Enbridge Sustain to Enbridge Gas for goods or services received in 2025.

Table 1

Amounts paid by Enbridge Sustain to Enbridge Gas for services received in 2025

Line No.	Cost Types	2025 Actual ($ millions)	Comments
1	Indirect Costs	$0.45	EGI Full Time Employees (FTE) providing services to Enbridge Sustain at a Fully Allocated Cost (FAC).
2	Direct Allocation: Real Estate	0.23	Real Estate costs for Ontario occupancy of Enbridge Sustain employees.
3	Direct Allocation: TIS	0.02	Shared IT support costs.
4	Total	$0.70	

8. Additionally, in each annual Deferral Account Clearance Application, Enbridge Gas has agreed to file (i) financial information relating to the business of Enbridge Sustain to provide context for the OEB to assess the affiliate transactions information provided; and (ii) a detailed list of all of the resources of Enbridge Gas that are used by Enbridge Sustain, all of the resources of Enbridge Sustain that are used by the utility, and all of the resources of any person that are shared between the utility and Enbridge Sustain, including an explanation of the cost allocation methodology for each.[5]

[4] Escalation at Price Cap Index of 3.33% (PCI) plus Growth of 0.48% = Base $1M x 1.0381 = $1.038 million.
[5] EB-2024-0111, Decision on Settlement Proposal and Interim Rate Order, November 29, 2024, p.57.

9. Table 2 presents the 2025 financial information for Sustain on an actuals basis.

Table 2

2025 Financial Information – Enbridge Sustain

Line No.	Cost Types	2025 Actual ($ millions)	Comments
1	Direct Costs	$10.5	Paid directly: does not flow through Utility
2	HR Benefits	2.4	Paid directly: does not flow through Utility
3	Indirect Costs[1]	0.5	Charged to Enbridge Sustain from Regulated Utility at Fully Allocated Cost Rate (FAC)
4	Corporate Cost Allocations	2.1	Paid directly: does not flow through Utility
5	Direct Allocations[2]	0.2	Direct charge to Enbridge Sustain at actual cost incurred
6	Total	$15.7	

Notes:
1) see Table 1 'Indirect Costs', as well as Table 3 for further details
2) see Table 1 'Direct Allocation: Real Estate' and 'Direct Allocation: TIS'

10. Table 3 presents Indirect Labour Costs at a Fully Allocated Cost Rate (FAC), broken down by department.

Table 3

2025 Details of Indirect Labour Charges – Enbridge Gas to Enbridge Sustain

Line No.	Department	Total Hours	Cost ($ millions)
1	Commercial & Regulatory Services	13	$0.005
2	Engineering	28	0.004
3	Finance	415	0.066
4	Legal	215	0.042
5	Operations	116	0.016
6	Public Affairs	17	0.003
7	Supply Chain	179	0.026
8	TIS	1,976	0.286
9	Business Development	200	0.023
10	Human Resources	8	0.002
11	Total	3,167	$0.473

11. All Enbridge Gas employees track hours worked for Enbridge Sustain and provide this information to Finance on a monthly basis. The Fully Allocated Cost Rates are then applied to their hours worked and charged to Enbridge Sustain. A corresponding credit is applied to Enbridge Gas's Regulated Line of Business to remove these costs from Enbridge Gas regulated OM&A.

3. Account No. 179-325 Open Bill Extension Deferral Account

12. The final balance in the account was brought forward for disposition in the 2024 Utility Earnings and Disposition of Deferral and Variance Account proceeding[6]. The program was discontinued as of October 31, 2024, and no balance will be recorded

[6] EB-2025-0155, Exhibit D, Tab 1, Schedule 2.

in the account going forward. As such, Enbridge Gas requests that this account be approved for closure.

13. The following accounts have balances but are not requested for clearance, however information supporting each balance is provided for information purposes:

- IRP Operating Costs Deferral Account
- IRP Capital Costs Deferral Account
- Panhandle Regional Expansion Project Variance Account
- Site Restoration Costs Variance Account

4. Account No. 179-318 - IRP Operating Costs Deferral Account

14. In its Decision and Order dated June 25, 2026, the OEB defers consideration of the costs incurred in the Southern Lake Huron project on the basis that it is premature to consider those costs given that the Southern Lake Huron project is not sufficiently advanced to determine if it is appropriate for ratepayers to pay the costs incurred. When Enbridge Gas is in a position to report on the results from the project, it can seek disposition of the associated balance at that time, as part of a DVA application.[7]

15. As a result, Enbridge Gas has included the cumulative operating costs attributable to the Southern Lake Huron (SLH) Pilot Project as not requested for clearance and will bring the balances forward in a future proceeding. See Table 4 below for details.

[7] EB-2025-0155, Decision and Order, p.11.

Table 4

Southern Lake Huron Project Operating Costs

Line No.	Particulars ($000's)	Actuals
1	2023 Operating Costs	34.0
2	2024 Operating Costs	78.0
3	2025 Operating Costs	2,122.6
4	Cumulative Total	2,234.6

5. Account No. 179-319 - IRP Capital Costs Deferral Account

16. As with the treatment of the IRP Operating Costs Deferral Account above, Enbridge Gas is also including the 2025 revenue requirement recorded in the IRP Capital Costs Deferral Account as a balance not being requested for clearance. The balance in the account is a credit of $3.0 thousand, plus interest. This amount is attributable to the SLH Pilot Project, as outlined below. Table 5 provides the calculation of the 2025 IRP Capital Costs Deferral Account balance.

Table 5
IRP Capital – SLH Pilot
Revenue Requirement Summary

Line No.	Particulars	2025
	Rate Base Investment:	
1	Capital Expenditures	158,914
2	Cumulative Capital Expenditures	158,914
3	Average Investment	6,621
	Revenue Requirement Calculation:	
	Operating Expenses:	
4	Operating and Maintenance Expenses	-
5	Depreciation Expense (1)	-
6	Property Taxes	-
7	Total Operating Expenses	-
8	Required Return (2)	403
9	Total Operating Expense and Return	403
	Income Taxes:	
10	Income Taxes - Equity Return (3)	84
11	Income Taxes - Utility Timing Differences (4)	(3,438)
12	Total Income Taxes	(3,354)
13	Total Revenue Requirement	(2,951)

Notes

(1) Depreciation is recorded in the month following the in-service date. SLH went into service in December 2025, therefore, depreciation will commence in January 2026.
(2) The required return assumes a capital structure of 62% long-term debt at 4.17% and 38% common equity at the 2024 OEB Formula return of 9.21%. The annual required return calculation is as follows: Average Investment (line 3)* 62% * 4.17% plus Average Investment (line 3)* 38% * 9.2
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year. Does not include Accelerated CCA as per RIIP/Bill C-15; RIIP/Bill C-15 impacts are captured in the TVDA, see Exhibit C, Tab 2, Schedule 12.

6. Account No. 179-329 Panhandle Regional Expansion Project Variance Account (PREPVA)

17. In its 2024 Rebasing Phase 1 Decision[8], the OEB approved the establishment of the PREPVA. 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. The actual net revenue requirement includes costs associated with the capital investment, including return on rate base, depreciation expense, and associated income taxes, as well as incremental operation and maintenance costs and property taxes, offset by transmission margin revenue associated with incremental demands served by the project. The actual revenues will be those collected through the PREP unit rate approved by the OEB for the Company.

18. In the 2024 Rebasing Phase 2 Settlement Agreement[9] the OEB approved unit rates reflecting levelized rate treatment for the PREP starting in 2025.

19. With the approval of the levelized rate treatment and PREPVA, Enbridge Gas will accumulate in the PREPVA over the IR term the net annual variance between the actual net revenue requirement and the amounts collected in rates based on the levelized rate. 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.

20. The Panhandle Regional Expansion Project went into service in December 2024 with an in-service cost of $234.0 million and an associated actual net revenue sufficiency (or credit) of $14.3 million for 2024. The balance in the PREPVA as of December 31, 2025 of $10.2 million, reflects the revenue sufficiency credit of $14.3

[8] EB-2022-0200, OEB Decision and Order, December 21, 2023, p.124.
[9] EB-2024-0111, Settlement Agreement, November 29, 2024, p.15.

million in 2024, partially offset by a revenue deficiency of $4.1 million in 2025, which will be carried forward and accumulated with each year's net amount through the IR term as noted above. There was an additional $8.5 million of capital expenditures in 2025 that were deferred from 2024, resulting in total cumulative capital expenditures of $242.4 million compared to the originally approved amount of $250.8 million. The lower than forecast (or approved) level of expenditures required for the project has resulted in lower depreciation expense as well as a lower required return and also affected the timing of tax impacts. Please see Table 6 for details of the revenue requirement for 2025 and Table 7 for the cumulative variance that has been recorded in the deferral account to date.

Table 6
Panhandle Regional Expansion Project
2025 Revenue Requirement Summary

Line No.	Particulars ($000s)	2025 Actual	2025 OEB-Approved	Variance
		(a)	(b)	(c)
	Rate Base Investment			
1	Capital Expenditures	8,464	0	8,464
2	Cumulative Capital Expenditures	242,439	250,830	(8,391)
3	Average Investment	237,489	248,759	(11,270)
	Revenue Requirement Calculation			
4	Operating & Maintenance Expenses	127	127	0
5	Depreciation Expense	3,467	3,678	(211)
6	Property Taxes	927	855	72
7	Total Operating Expenses	4,520	4,659	(139)
8	Required Return	14,448	15,133	(685)
9	Total Operating Expenses and Return	18,968	19,792	(824)
	Income Taxes			
10	Income Taxes - Equity Return	2,997	3,139	(142)
11	Income Taxes - Utility Timing Differences	(5,157)	(4,692)	(465)
12	Total Income Taxes	(2,161)	(1,553))	(608)
13	Total Revenue Requirement	16,807	18,240	(1,433)
14	Incremental Project Revenue	4,182	4,000	182
15	Net Revenue Requirement	12,625	14,240	(1,615)

Table 7
Panhandle Regional Expansion Project
Cumulative Revenue Requirement Continuity (2024-2028)

Line No.	Particulars ($ millions)	2024 Actual (a)	2025 Actual (b)
	Rate Base Investment		
1	Capital Expenditures	234.0	8.5
2	Cumulative Capital Expenditures	234.0	242.4
3	Average Investment	8.8	237.5
	Revenue Requirement Calculation		
4	Operating & Maintenance Expenses	0	0.1
5	Depreciation Expense	0	3.5
6	Property Taxes	0.3	0.9
7	Total Operating Expenses	0.3	4.5
8	Required Return	0.5	14.4
9	Total Operating Expenses and Return	0.9	19.0
	Income Taxes		
10	Income Taxes - Equity Return	0.1	3.0
11	Income Taxes - Utility Timing Differences	(15.0)	(5.2)
12	Total Income Taxes	(14.9)	(2.2)
13	Total Revenue Requirement	(14.0)	16.8
14	Incremental Project Revenue	0.3	4.2
15	Net Revenue Requirement	(14.3)	12.6
16	Actual Revenue Collected in Rates	0.0	8.5
17	Variance	(14.3)	4.1
18	Cumulative Variance	(14.3)	(10.2)

7. Account No. 179-337 Site Restoration Costs Variance Account (SRCVA)

21. In its 2024 Rebasing Phase 1 Interim Rate Order,[10] the OEB approved the establishment of the SRCVA and directed Enbridge Gas to discontinue using site restoration amounts collected through depreciation recovered in rates to offset other costs and instead segregate monies collected through rates for site restoration beginning in 2024.

22. Commencing January 1, 2024, the purpose of this account is to record and track the cumulative amount of site restoration costs collected through depreciation in rates versus actual spending related to site restoration, net of any proceeds from disposition. A net credit balance will represent amounts available to offset future decommissioning, abandonment, or site restoration costs. A net debit balance in the account, reflecting actual site restoration costs exceeding amounts recovered via depreciation expense, will reflect an offset to the cumulative pre 2024 SRC liability, of $1.718 billion, currently reflected in accumulated depreciation. 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. However, the balance will be presented in the Company's annual application to dispose of deferral and variance account balances.

23. The amount of site restoration costs recovered in rates is derived by applying the net salvage component in approved depreciation rates to actual gross plant values. Where the cumulative amount of site restoration amounts recovered exceeds the cumulative actual cost of decommissioning, abandonment, and site restoration (net of any proceeds), the net balance will be set aside and maintained in a distinct interest-bearing bank account for the duration of the incentive rate-setting

[10] EB-2022-0200, Decision on Interim Rate Order, April 11, 2024, p.11.

mechanism term. The cash balances in this bank account will earn interest income based on the prime rate, less a discount, set by Canadian financial institutions and influenced by the Bank of Canada. Any after-tax interest earned on the balance set aside, as well as any related fees, is recorded in the SRCVA. Income generated from the balance set aside will effectively reduce or offset the total amount of site restoration funds required to be collected in the future. This will benefit ratepayers through future depreciation rates.

24. At the end of 2024 Enbridge Gas had a net credit balance of $19.430 million in the SRCVA account. As at December 31, 2025, the cumulative balance in the SRCVA is a credit of $15.616 million. During 2025, Enbridge Gas recovered and recorded $95.495 million of site restoration in depreciation rates, and incurred $100.019 million of decommissioning, abandonment, and site restoration costs (net of any proceeds), resulting in a net debit activity amount of $4.524 million. The total after-tax interest generated during 2025 (net of bank fees) on the net cumulative credit balance totaled $0.710 million. A summary of the SRCVA balance is provided in Table 8.

Table 8
2025 Site Restoration Cost Variance Account (SRCVA)

Line No.	Particulars ($ millions)	2025 Actuals
1	Opening Balance	(19.430)
2	Site Restoration Recovered in Depreciation Rates	(95.495)
3	Decommissioning, Abandonment, and Site Restoration Costs	100.019
4	Interest Income (After-Tax)	(0.710)
5	Net SRCVA Balance as of Dec 31, 2025	(15.616)

ACCOUNT NO. 179-88 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT
EGD RATE ZONES

1. The purpose of the 2025 Storage & Transportation Deferral Account (S&TDA) is to record the difference between the forecast cost of market-based storage (MBS) included in the Company's approved rates and the actual cost of MBS incurred by the Company. The S&TDA also records amounts allocated to the EGD rate zone from the disposition of Union rate zone deferral and variance account balances related to services rendered to EGD rate zone customers.

2. The balance in the 2025 S&TDA that the Company is proposing to collect from customers is $3.1 million, plus interest. A detailed breakdown of the S&TDA is provided at Table 1.

Table 1
Breakdown of the 2025 S&TDA - EGD rate zone

Line No.	Particulars ($ millions)	Forecasted Costs (a)	Actual Costs (b)	Variance (c)
1	Market-Based Storage	20.2	24.2	4.0
2	2023 ESM/DVA Disposition (1)	-	(0.9)	(0.9)
3	Total	20.2	23.3	3.1

Notes:
(1) Disposition of 2023 Deferral and Variance Account (EB-2024-0251) refund balance related to the EGD rate zone: M12 transportation of $0.9 million, M16 transportation of $0.001 million.

3. The primary driver for the balance in the 2025 S&TDA is higher than forecasted MBS costs in 2025 of $24.2 million, which is $4.0 million higher than the OEB-approved 2025 MBS costs of $20.2 million, partially offset by an OEB-approved $0.9 million refund from the Union rate zones to the EGD rate zone.[1] The increase in 2025 MBS costs was driven by the higher average storage cost in 2025 of $1.21

[1] Disposition of 2023 Deferral and Variance Account (EB-2024-0251) balances-related refund to the EGD rate zone: M12 transportation of $0.9 million, M16 transportation of $0.001 million.

CAD/GJ compared to the average storage cost included in the OEB-approved 2025 MBS costs of $0.78 CAD/GJ, partially offset by a reduction in total MBS contracted in 2025 from 26 PJ to 17 PJ.[2] As part of the Company's OEB-approved 2024 Rebasing Phase 2 Settlement Agreement, Enbridge Gas committed to report annually on its MBS and load balancing costs.[3,4]

1. Market Based Storage

4. In 2025, Enbridge Gas held 199.7 PJ of cost-based storage reserved for in-franchise customers to meet their planned load balancing requirements: 99.7 PJ for the EGD rate zone, and 100 PJ for the Union rate zones. In addition, the Company held 26 PJ of MBS until March 31, 2025, and 17 PJ of MBS effective April 1, 2025, for the EGD rate zone (including 270 TJ/d and 178 TJ/d, respectively, of related maximum MBS withdrawal capabilities).

5. The reduction in MBS effective April 1, 2025, is consistent with the commitment made by Enbridge Gas as part of its 2024 Rebasing Phase 2 Settlement Agreement where the Company agreed to reduce MBS from 26 PJ to 18 PJ (a reduction of 8 PJ) by not-renewing a portion of expiring MBS service contracts in 2025, and to manage load balancing requirements above 217.7 PJ in a manner the Company deems appropriate.[5] As outlined in the Company's 2026 Annual Gas Supply Plan Update and discussed in further detail below,[6] Enbridge Gas elected to further reduce its contracted MBS by 1 PJ in 2025 and instead procure an additional 1 PJ of planned supply at Dawn through the Company's typical commodity RFP process during the winter 2025/26 season, as needed.

[2] The average storage cost in 2024 of $1.09 CAD/GJ was also higher than the average storage cost included in the OEB-approved 2024 MBS costs (EB-2025-0155, Exhibit D, Tab 1, Schedule 1).
[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, pp.23-24.
[4] Load balancing reporting included at Exhibit G, Tab 5, Schedule 1.
[5] EB-2024-0111, Exhibit N, Tab 1, Schedule 1, pp.9-10 & 23-24.
[6] EB-2026-0092, Enbridge Gas 2026 Annual Gas Supply Plan, Section 3.4.

6. The cost in rates for 199.7 PJ of cost-based storage is set through a cost-of-service rate application. The cost in rates of MBS is forecast in a cost-of-service rate application with cost variances recorded in the S&TDA. In 2025, the forecast cost in rates and actual cost of MBS contracted for the EGD rate zone was $20.2 million and $24.2 million, respectively, as shown in Table 1.

7. As discussed recently in the Company's 5-Year Gas Supply Plan,[7] Enbridge Gas purchases MBS services on behalf of customers in the EGD rate zone through a competitive blind RFP process. On February 5, 2025, a third-party RFP manager initiated the RFP process for MBS services at Dawn by distributing an RFP letter to storage service providers (see Exhibit D, Tab 2, Schedule 1) requesting offers for firm storage services of up to 2 PJ, terms of up to five years commencing April 1, 2025, and firm injections from May to September and firm withdrawals from December to March (the 2025 Blind RFP). The RFP responses were received by the RFP manager on behalf of Enbridge Gas on February 26, 2025, after which the RFP manager made a procurement recommendation based on the Company's evaluation criteria.[8]

8. The 2024 Rebasing Phase 2 Settlement Agreement included the requirement for Enbridge Gas to consider alternatives to MBS available at the time storage contracting decisions were made and to report on the alternatives assessed (including pricing) as part of the Company's annual deferral and variance account disposition proceedings. Accordingly, Table 2 provides a comparison of the price of alternatives assessed at the close of the 2025 Blind RFP process. The alternatives assessed include High-Flexibility and Low-Flexibility storage services (based on service offering(s) bid in the Blind RFP and forward market settlement prices on

[7] EB-2025-0065, Enbridge Gas 5-year Gas Supply Plan, pp.45-48.
[8] The details of all MBS service offerings received and recommended by the RFP manager are outlined at Confidential Exhibit D, Tab 2, Schedule 2.

February 26, 2025) and Delivered Supply at Dawn (based on forward market settlement prices on February 26, 2025).

Table 2[9]
Comparison of MBS and Alternatives

Line No.	Particulars ($CAD/GJ)	Annualized Cost (a)
1	High-Flexibility MBS	5.68
2	Low-Flexibility MBS	5.43
3	Delivered Supply	6.21

9. Recognizing its reliability and cost-effectiveness, and consistent with the Company's 2024/25 gas supply plan, Enbridge Gas procured 1 PJ of High-Flexibility MBS services for a five-year term through the Blind RFP process in 2025 to maintain sufficient storage capacity and related late winter season deliverability. The Company's decision was informed by the following factors:

   (i) The RFP manager's recommendation to contract for up to 2 PJ of High-Flexibility MBS services for a five-year term (as detailed in Confidential Exhibit D, Tab 2, Schedule 2).

   (ii) 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).

[9] The costs set out in Table 2 are based on the price of the storage service offerings recommended by the blind RFP manager and average forward NYMEX and Dawn basis prices (five-year average of monthly prices from May-September from 2025-2029 used for storage services, and one-year average of monthly prices from December-February 2025/26 used for delivered supply only). Enbridge Gas did not speculate on the future price differences that may occur between delivered supply purchased on a fixed-price contract vs. indexed-price contract. Commodity price detail underlying the information presented in Table 2 is proprietary in nature.

(iii) The Company's goal of re-establishing a consistent balance of MBS contract term diversification within three years (limiting ratepayer exposure to annual storage service price fluctuations).[10] To improve the contract term diversity of the MBS services portfolio in 2025, Enbridge Gas sought to contract for services with a five-year term.[11]

(iv) The Company's preference (in the 2025 Blind RFP) for High-Flexibility MBS services because of the additional operational flexibility they typically afford, the fact that no bid for Low-Flexibility MBS services with a five-year term was offered,[12] and Enbridge Gas's goal as described in (iii) to re-establish balanced MBS contract term diversity.[13]

(v) The results of Enbridge Gas's assessment of alternatives (see Table 2 and Confidential Exhibit D, Tab 2, Schedule 2), which indicate that no amount of Low-Flexibility MBS services with a five-year term was available, and that Delivered Supply contracted in the forward market at that time would be higher cost than MBS services (High or Low-Flexibility).

[10] Due to the changes made as part of the Company's 2024 Rebasing Phase 2 Settlement Agreement to reduce the volume of MBS services contracted, Enbridge Gas anticipated that it would take at least 3 years to adjust MBS contract service terms to achieve a consistent volume of third-party storage service purchases annually.
[11] See the Company's 2026 Gas Supply Plan Annual Update for a summary of MBS contract volumes and terms at EB-2026-0092, Section 3.4, Table 10.
[12] See Confidential Exhibit D, Tab 2, Schedule 2.
[13] In the Company's experience, Low-Flexibility storage service providers typically only bid/contract for service terms of three years or less.

Enbridge Gas
50 Keil Drive North
Chatham, Ontario N7M 5M1
Canada

February 5, 2025

Dear Recipient,

Subject: Storage at Dawn, Injections commencing April 1, 2025

Enbridge Gas Inc. operating as Enbridge Gas Distribution (Enbridge Gas) is seeking to procure firm natural gas storage services with injections commencing April 1, 2025.

This storage service request for proposal (RFP) is being administered by Ernst & Young LLP on behalf of Enbridge Gas.

Enbridge Gas is seeking storage services that meet or exceed the characteristics set out below, including services providing higher withdrawal capabilities and access to multiple daily nomination windows.

Storage Service Characteristics
To be considered, Enbridge Gas requires that all storage service offerings meet the following minimum service specifications:

- **Term:** Enbridge Gas's preference is to contract for a combination of 3-year and 5-year service terms, commencing April 1, 2025. However, service offerings including up to five (5) years will be considered. The volume and term of storage services ultimately contracted will be at Enbridge Gas's sole discretion.

- **Location:** Enbridge Gas will deliver natural gas volumes to the Storage Provider at Union Dawn for injection, and the Storage Provider will re-deliver natural gas volumes to Enbridge Gas at Union Dawn for withdrawal. If any transportation capacity is included as part of the storage service offering to facilitate Dawn injections and withdrawals, please include a detailed description of the characteristics of the transportation service.

- **Firm Injections:** Must include the months from May 1 through September 30. Service offerings that require Enbridge Gas to inject into storage during the months of November and December will be considered non-conforming.

- **Firm Withdrawals:** Enbridge Gas maintains a portfolio of storage services with either high or low withdrawal flexibility and is seeking offers of both types of services in this RFP.
    - **High Flexibility Services:** Minimum of 1.2% firm peak withdrawal capability. Must include the months from December 1 through March 31.

- **Low Flexibility Services:** Minimum 0.826% withdrawal rights to fully empty storage from December 1st through March 31st. Service offerings that require Enbridge Gas to withdraw from storage during other months will be considered non-conforming.

Storage Service Offerings

Storage service offerings should adhere to the format set out, and include all of the details requested, within the attached Microsoft Excel form, including delivery points, service term, maximum storage balance (MSB), price (including demand and commodity charges), a detailed description of all relevant service attributes, and sample invoices.[1]

Prior to contract execution, storage service providers must have established sufficient credit with Enbridge Gas. Counterparties are encouraged to contact Enbridge Gas's credit department to discuss their credit position via email to egicredit@Enbridge.com.

Please submit any questions regarding Enbridge Gas's RFP, as well as your storage service offering(s) to the attention of Chester Mercier via email to chester.mercier@EY.com.

- The deadline to submit any questions regarding Enbridge Gas's RFP is **12 p.m. (noon) Eastern Time (ET) on February 10, 2025**. A record of all questions received and all responses delivered will be distributed to all participants as promptly as possible in advance of the deadline to submit storage service offerings.
- The deadline to submit storage service offerings is **9 a.m. Eastern Time (ET) on February 26, 2025**.[2]

DO NOT CONTACT ENBRIDGE GAS PERSONNEL DIRECTLY REGARDING THIS RFP

[1] This storage service request may have Dodd Frank Act implications and may require specific clauses to be included in any storage agreement between the parties. Any such storage agreement will not be binding until a definitive agreement is executed by the parties.

[2] Please note that successful storage service providers must meet all of Enbridge Gas's credit criteria. Enbridge Gas, in its sole discretion and for whatever reason, may accept or reject any and all offerings. Enbridge Gas reserves the right at any time after the deadline for offerings, to conduct negotiations with one or more of the participants to the exclusion of others, and such negotiations may include changes to the storage service characteristics described in this letter.

Additional Information

Enbridge Gas invites all potential participants to review a presentation that has been posted to the Storage and Transportation section of its website at the following hyperlink: https://www.enbridgegas.com/storage-transportation/news-presentations.

Enbridge Gas will contact successful bidders following the close of the RFP process.

Sincerely,

Chester Mercier

Ernst & Young LLP

2025 Storage RFP - Issued on 2/05/2025; Responses on 02/26/2025 ; Bid Refreshed on 02/27/2025 - All responses summary

=RFP Manager recommendations

Response	Total cost (CAD/GJ)	Total Annual cost - 1 turn - CAD	Total Annual cost - 1PJ - CAD	Term (years)	Volume (GJ)	High/Low flexibility	Max Withdrawal rights - %	Ratchet score / # of days to w/d	max Injection rate (GJ/day)	max Withdrawal rate (GJ/day)	Days to Inject	Notes
[redacted]												

ACCOUNT NO. 179-108 UNABSORBED DEMAND COSTS VARIANCE ACCOUNT UNION RATE ZONES

1. The balance in the Unabsorbed Demand Cost (UDC) Variance Account is a debit from ratepayers of $4.882 million, plus interest. The $4.882 million debit balance is the difference between the actual UDC incurred and the amount of UDC costs collected in rates for the Union rate zones. There was no change to how the account operated in 2025 as compared to prior years.

1. Background

2. As discussed in Enbridge Gas's 2025 5-Year Gas Supply Plan,[1] the Company maintains a portfolio of upstream transportation assets to meet the design day demand requirements of its customers. Enbridge Gas plans for unutilized pipeline capacity in the Union North rate zones because the amount of transportation capacity needed to meet average annual demand requirements is less than the capacity required to meet design day demand requirements. Accordingly, Enbridge Gas's 2025 rates include costs associated with 14.4 PJ of planned unutilized pipeline capacity (UDC) for the Union North rate zones (3.1 PJ for Union North East, and 11.3 PJ for Union North West).[2]

3. On an actual basis, UDC costs may be incurred in any of the Union rate zones, including Union South. For example, in a warmer than normal year, additional UDC may be incurred in Union North, and UDC may be incurred in Union South, to balance supply with lower demands. Enbridge Gas manages its portfolio of upstream transportation assets on an integrated basis and decisions as to which

[1] EB-2025-0065, Enbridge Gas's 2025 5 Year Gas Supply Plan, p.44.
[2] Based on the annual gas supply plan filed as part of Enbridge Gas's Dawn Reference Price proceeding: EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1.

pipeline to leave unutilized are primarily based on the least cost option and consideration of operational constraints.[3]

4. The following sections detail 2025 UDC capacity, costs, and related revenues generated through the release of unutilized pipeline capacity to secondary markets as well as the balances recorded in the UDC Variance Account for which Enbridge Gas is seeking disposition.

2. UDC Volumes, Costs & Capacity Release Revenues

5. Table 1 provides total actual UDC capacity, associated UDC costs incurred, and related capacity release revenues generated by Enbridge Gas in 2025 assigned to each rate zone based on the unutilized capacity allocation in rates. Enbridge Gas experienced UDC amounting to 32,516 TJ in 2025, due to a range of factors, including but not limited to planned UDC (as explained above), supply interruptions/curtailment and weather-driven variability in customer consumption. Enbridge Gas incurred gross UDC costs associated with the UDC capacity of $15.792 million. Enbridge Gas generated revenues by releasing a portion of this unutilized pipeline capacity to secondary markets of $4.645 million.[4]

[3] Some unutilized upstream transportation capacity may be released and sold on the secondary market to minimize UDC costs. The revenues generated from transportation capacity released is credited to the UDC Variance Account mitigating the overall impact of UDC costs to ratepayers as shown in Table 2.
[4] Not all unutilized upstream transportation capacity is released and sold on the secondary market (e.g., unplanned interruptions or curtailment may preclude timely capacity release, or there may be operational reasons not to release unutilized capacity).

Table 1
Actual 2025 UDC Capacity, Costs & Capacity Release Revenues
Rate Zone Presentation Based on Unutilized Capacity Allocation in Rates

Line No.	Particulars	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	UDC Capacity (TJ)	13,922	10,655	7,939	32,516
2	UDC Costs Incurred ($000s)	5,010	5,069	5,713	15,792
3	Capacity Release Revenues ($000s)	0	(4,581)	(64)	(4,645)

3. Derivation of 2025 UDC Variance Account Balances

6. Table 2 derives UDC variance account balances by rate zone by calculating the difference between UDC costs collected in rates and net UDC costs incurred by Enbridge Gas in 2025, including interest. Enbridge Gas collected $6.266 million in rates for UDC in 2025.[5] Enbridge Gas allocated UDC costs of $15.792 million and revenues generated through capacity release of $4.645 million to each rate zone in proportion to the actual supply and demand variances by rate zone,[6] resulting in net UDC costs of $11.147 million.[7] The variance between the UDC costs collected in rates and net UDC costs incurred, results in a net debit from ratepayers in the UDC Variance Account of $4.882 million, plus interest.

[5] The 2025 OEB-approved rates include $6.232 million of UDC costs associated with 14.4 PJ of planned unutilized pipeline capacity in the Union North East and Union North West rate zones, and TCPL Mainline tolls effective January 1, 2025. On an actual basis in 2025, Enbridge Gas recovered $6.266 million of UDC costs from customers in the Union North East and Union North West rate zones.
[6] Union North East = 31%, Union North West = 13%, Union South = 56%.
[7] Net UDC costs are removed (credited) from the Gas Cost Deferral Accounts, where transportation demand charges are recorded, and reallocated (debited) to the UDC Variance Account monthly to ensure that costs are assigned to the appropriate deferral account and eliminate risk of double counting.

Table 2

UDC Variance Account Balances by Rate Zone

Line No.	Particulars ($000s)	Union North East	Union North West	Union South	Total
		(a)	(b)	(c)	(d)
1	UDC Costs Collected in Rates	(1,318)	(4,947)	-	(6,266)
2	UDC Costs Incurred (1)	4,937	2,015	8,840	15,792
3	Capacity Release Revenues (1)	(1,452)	(593)	(2,600)	(4,645)
4	Net UDC Costs Incurred (Line 2 + Line 3)	3,485	1,422	6,240	11,147
5	UDC Cost Variance (Line 1 + Line 4)	2,166	(3,525)	6,240	4,882

Note:

(1) UDC Costs Incurred (Table 1, Line No. 2) and Released Capacity Revenue (Table 1, Line No. 3) re-allocated to Union North East (31%), Union North West (13%), and Union South (56%) rate zones in proportion to the actual supply and demand variances by rate zone.

ACCOUNT NO. 179-70 SHORT-TERM STORAGE AND OTHER BALANCING SERVICES – UNION RATE ZONES

1. In Phase 1 of the 2024 Rebasing Application, Enbridge Gas proposed that the excess utility storage space that previously existed in the Union rate zones would be used to serve all Enbridge Gas in-franchise customers as part of the consolidated gas supply plan[1].

2. In accordance with the 2024 Rebasing Phase 1 Settlement Agreement[2] matters related to storage would be determined in Phase 2 and parties agreed that Enbridge Gas would maintain its current levels of market-based storage until the determination on storage was made in Phase 2. The 2024 Rebasing Phase 2 Settlement Agreement[3] reduced the level of market-based storage to be held by Enbridge Gas. The reduction in market-based storage levels was completed by way of contracts which expired on March 31, 2025.

3. Enbridge Gas continued to maintain excess utility storage space in the Union rate zones until the implementation of the storage space outcomes of the 2024 Rebasing Phase 2 Settlement Agreement[4] effective April 1, 2025. During the period up to April 1, 2025, Enbridge Gas continued to record the net ratepayer benefit from the sale of excess utility storage in the Short-Term Storage Deferral Account.

4. The Short-Term Storage and Other Balancing Services Deferral Account includes revenues from C1 Short-Term Firm Peak Storage, C1 Off-Peak Storage, Loans, and Balancing Services. The deferral account balance is comprised of the actual gross revenues from short-term and other balancing services from the sale of available excess utility storage space, less the net shareholder incentive. The balance in this

[1] EB-2022-0200, Exhibit 4, Tab 2, Schedule 1.
[2] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023.
[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024.
[4] Ibid.

deferral account is a payable to ratepayers of $0.599 million, plus interest.

5. As shown in Table 1, the balance is calculated by adding the ratepayer 90% share of the actual 2025 Short-Term Storage and Other Balancing Services revenue (line 6) plus the shareholder 10% portion of the actual 2025 Short-Term Storage and Other Balancing Services cost (line 11). The 2024 Test Year Forecast included in rates assumed no excess utility space and ratepayers have paid 100% of the costs associated with excess utility space. As such, Enbridge Gas will credit the 10% shareholder portion of the costs to the ratepayer as part of the determination of the deferral account balance.

Table 1

Breakdown of Short-term Storage Deferral Account

Line No.	Particulars ($ millions)	Actual 2025
		(a)
	Revenue	
1	Peak Storage	0.20
2	Off-Peak Storage	0.01
3	Loans	0.00
4	Short-term Balancing	0.41
5	Total Revenue	0.61
6	Ratepayer portion of revenue (90%)	0.55
	Costs	
7	O&M (1)	0.04
8	UFG (2)	0.32
9	Compressor Fuel (3)	0.11
10	Total Costs	0.46
11	Ratepayer refund of costs (10%)	0.05
12	Deferral Balance Payable to Ratepayers	0.60

Notes:
(1) Revenue Requirement on 11.3 PJ of 2013 OEB-approved excess in-franchise storage capacity.
(2) Based on short-term storage volumes in proportion to total volumes.
(3) Based on short-term storage activity in proportion to actual storage activity.

6. There is no longer excess utility space and any changes in customer storage requirements are managed through the gas supply plan.

2. Sale of Non-Utility Storage Space

7. As described above, in 2025, Enbridge Gas did not sell non-utility short-term peak storage. The excess utility space that was sold in 2024 expired March 31, 2025. Table 2 details the short-term peak storage revenue from January 1 to March 31, 2025.

Table 2
2025 Allocation of Short-Term Peak Storage Revenues Between Utility and Non-Utility

Line No.	Particulars	Utility Storage Space (PJ)	Space Sold (PJ) (1)	Revenue ($ millions)
		(a)	(b)	(c)
1	Short-Term Peak Storage		-	0.7
2	Utility Storage Space	100.0		
3	Utility Space Requirement	100.0		
4	Excess Utility Storage Space	-		
5	Utility Short-Term Peak Storage Sales		-	0.2
6	Non-Utility Short-Term Peak Storage Sales		-	0.5

ALLOCATION AND DISPOSITION OF 2025 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The purpose of this evidence is to address the allocation and disposition of 2025 deferral and variance account balances identified at Exhibit C, Tab 1, Schedule 1.

2. Enbridge Gas proposes to dispose of the 2025 deferral and variance account balances with the first QRAM application following the OEB's approval, as early as July 1, 2027.

3. This exhibit of evidence is organized as follows:
   1. Allocation of Deferral and Variance Accounts
      - 1.1 EGI Accounts
      - 1.2 EGD Rate Zone Accounts
      - 1.3 Union Rate Zones' Accounts
   2. Disposition of Deferral and Variance Accounts
   3. General Service Bill Impacts

1. Allocation of Deferral and Variance Accounts

4. In accordance with the 2024 Rebasing Phase 1 Settlement Agreement[1], Phase 1 Decision[2], and Phase 2 Settlement Agreement[3], the OEB approved the establishment of new and harmonized Enbridge Gas deferral and variance accounts that apply to both the EGD rate zone and Union rate zones effective January 1, 2024. Certain existing standalone gas supply accounts specific to the EGD rate zone and Union rate zones will continue until harmonized rates are implemented, which is expected sometime in 2027.

[1] EB-2022-0200, Settlement Agreement, August 17, 2023.
[2] EB-2022-0200, Decision and Order, December 21, 2023.
[3] EB-2024-0111, Settlement Agreement, November 29, 2024.

1.1. EGI Accounts

5. The 2025 EGI deferral and variance account balances to be cleared, including the split of account balances by rate zone, are included at Exhibit F, Tab 1, Schedule 3.

6. As part of Phase 3 of the 2024 Rebasing Application[4], the Company requested approval of a Rate Harmonization Plan, including a harmonized cost allocation study. The OEB has approved the 2024 Rebasing Phase 3 Settlement Proposal[5], and the Company expects to implement the Rate Harmonization Plan sometime in 2027. Enbridge Gas will review and update the allocation of all deferral and variance accounts following the implementation of the Rate Harmonization Plan.

7. In the interim, Enbridge Gas proposes to allocate the deferral and variance account balances in a consistent manner with previous OEB-approved methodologies, where possible. Exhibit F, Tab 1, Schedule 2 provides a summary of the deferral and variance accounts included in this Application, the proposed allocation methodology, and reference to the history of each account (if applicable). The proposed allocation methodologies for new accounts with balances for disposition are described below.

8. Enbridge Gas is not requesting to dispose of the 2025 balances in the Incremental Capital Module Deferral Account, IRP Operating Costs Deferral Account, IRP Capital Costs Deferral Account, Panhandle Regional Expansion Project Variance Account, Site Restoration Costs Tracking Account, or Asset Life Extension Costs Deferral Account as part of this Application. There is no balance in the Unauthorized Overrun Non-Compliance Deferral Account, Expansion of Natural Gas Distribution Systems Variance Account, Green Button Initiative Deferral Account, Cloud Computing

[4] EB-2025-0064.
[5] EB-2025-0064, Decision on Settlement Proposal and Rate Order, March 26th, 2026.

Implementation Costs Deferral Account, Enbridge Sustain Affiliate Recoveries Variance Account, Open Bill Extension Deferral Account, Incremental Capital Module Deferral Account and Asset Life Extension Costs Deferral Account as shown at Exhibit C, Tab 1, Schedule 1.

9. The 2025 Earnings Sharing Deferral Account balance, including interest, is a credit of $25.233 million. Enbridge Gas proposes to split the balance between the EGD and Union rate zones in proportion to actual 2018 OEB-approved rate base. Further, Enbridge Gas proposes to allocate the respective balances to rate classes in proportion to rate base from the last OEB-approved cost allocation study for each rate zone. The proposed allocation factor is appropriate as it is consistent with the previous OEB-approved approach for the allocation of earnings sharing amounts for the EGD and Union rate zones.

10. The 2025 Tax Variance Account balance, including interest, is a credit of $13.969 million. Enbridge Gas proposes to split the balance between the EGD and Union rate zones in proportion to actual 2018 OEB-approved rate base. Further, Enbridge Gas proposes to allocate the respective balances to rate classes in proportion to rate base from the last OEB-approved cost allocation study for each rate zone. The proposed allocation factor is appropriate as taxes are allocated to rate classes in proportion to rate base.

11. The IRP System Pruning Deferral Account balance, including interest, is a debit of $0.415 million, consisting of a debit of $0.024 million related to the 2024 deferral balance and a debit of $0.391 million related to the 2025 deferral balance. Enbridge Gas proposes to split the 2024 and 2025 combined deferral balance of $0.415

million in proportion to the 2018 actual OEB-approved rate base for each rate zone[6] and allocate the respective balances to rate classes using rate base from the last OEB-approved cost allocation study for the EGD and Union rate zones[7]. Splitting the debit balance results in a debit of $0.219 million being allocated to the EGD rate zone and a debit of $0.196 million being allocated to the Union rate zones.

12. The 2025 Disposition of Property Deferral Account balance, including interest, is a credit of $13.493 million, consisting of a credit of $12.203 million to the EGD rate zone and a credit of $1.291 million to the Union rates zones based on the location of disposed property. Enbridge Gas proposes to allocate the respective balances to rate classes 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.

13. The 2025 OEB Cost Assessment Variance Account balance, including interest, is a debit of $3.119 million. Enbridge Gas proposes to split the balance between the EGD and Union rate zones in proportion to actual 2018 OEB-approved rate base. Further, Enbridge Gas proposes to allocate the balance related to the EGD rate zone to EGD rate classes in proportion to rate base from the last OEB-approved cost allocation study for the EGD rate zone. Enbridge Gas proposes to allocate the balance related to the Union rate zones to Union rate zone rate classes in proportion to the allocation of Administrative and General O&M expenses from the last OEB-approved cost allocation study for the Union rate zones. The proposed allocation factors are appropriate as it is consistent with the previous OEB-approved approach

[6] EGD rate zone as per EB-2019-0105, Exhibit B, Tab 2, Appendix B, Schedule 1. Union rate zones as per EB-2019-0105, Exhibit C, Tab 2, Appendix A, Schedule 4.
[7] 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.

for the allocation of OEB Cost Assessment amounts for the EGD and Union rate zones.

14. The 2025 Customer Carbon Charge Variance Account balance, including interest, is a credit of $0.002 million. Based on the account activity, the balance has been direct assigned to the EGD rate zone and allocated to EGD rate classes based on actual 2025 volumes subject to the Federal Carbon Charge. Enbridge Gas proposes to change the disposition methodology to include the rate class allocations of this account as part of the derivation of delivery unit rates for disposition as the balance is not significant enough to generate a unit rate based on 2025 volumes subject to the Federal Carbon Charge.

1.2 EGD Rate Zone Accounts

15. The 2025 deferral and variance account balances to be cleared to the EGD rate zone are provided at Exhibit F, Tab 1, Schedule 3.

16. The 2025 EGD rate zone deferral and variance account balances are allocated to rate classes using the same methodologies as approved by the OEB in previous years.

17. The allocation of account balances to EGD rate classes is provided at Exhibit F, Tab 2, Schedule 2.

1.3 Union Rate Zones' Accounts

18. The 2025 deferral and variance account balances to be cleared to the Union rate zones are provided at Exhibit F, Tab 1, Schedule 3.

19. The 2025 Union rate zones' deferral and variance account balances are allocated to rate classes using the same methodologies as approved by the OEB in previous years.

20. The allocation of account balances to Union South and Union North rate classes is provided at Exhibit F, Tab 3, Schedule 2.

2. Disposition of Deferral and Variance Accounts

21. Enbridge Gas proposes to dispose of the 2025 deferral and variance account balances with the first QRAM application following the OEB's approval.

22. Enbridge Gas proposes to dispose of the 2025 deferral and variance account balances as a one-time billing adjustment. The billing adjustment will appear as a separate line item on customers' bills. The billing adjustment will be derived for each customer by applying the disposition unit rates to each customer's actual consumption volume or contract demand, as applicable, for the period January 1, 2025, to December 31, 2025.

23. The unit rates for disposition by rate class and service type for the EGD rate zone are provided at Exhibit F, Tab 2, Schedule 1 and Schedule 3. The unit rates for disposition by rate class and service type for the Union rate zones, including a summary of the balances to be disposed of to ex-franchise rate classes are provided at Exhibit F, Tab 3, Schedule 1 and Schedule 3.

3. General Service Bill Impacts

24. For a Rate 1 sales service and western T-service customer in the EGD rate zone with annual consumption of 2,400 m^3, the one-time billing adjustment credit is $18.94.

25. For a Rate M1 sales service residential customer in Union South with annual consumption of 2,200 m^3, the one-time billing adjustment charge is $7.76. For a Rate M1 bundled direct purchase (DP) residential customer, the one-time billing adjustment charge is $0.42.

26. For a Rate 01 sales service and bundled DP residential customer in Union North West with annual consumption of 2,200 m^3, the one-time billing adjustment credit is $22.10.

27. For a Rate 01 sales service and bundled DP residential customer in Union North East with annual consumption of 2,200 m^3, the one-time billing adjustment credit is $7.28.

28. Bill impacts of the proposed disposition are provided at Exhibit F, Tab 2, Schedule 4 for the EGD rate zone and Exhibit F, Tab 3, Schedule 4 for the Union rate zones.

Enbridge Gas Inc.
Summary of Deferral and Variance Account Allocation Factors

Line No.	Account Description	Acct. No.	Reference	Allocator to Rate Zone	Allocator to Rate Class
			(a)	(b)	(c)
	EGI Commodity Related Accounts				
1	Upstream Transportation Optimization V/A	179-201	EB-2022-0200	Direct assigned in proportion to 2025 actual optimization activity	Allocation of actual optimization activity to the EGD rate zone rate classes in proportion to actual Sales and Western BT volumes. Allocation of actual optimization activity to the Union North rate zone rate classes in proportion to the optimization credit included in rates. Allocation of actual optimization activity to the Union South rate zone rate classes in proportion to Sales Service volumes.
2	UFG Volume V/A	179-203	EB-2022-0200	Direct assignment by rate zone	Allocation to EGD rate zone rate classes in proportion to actual volumes. Allocation to Union rate zone rate classes in proportion to the 2013 OEB approved allocation of UFG volumes, updated for 2025 activity.
3	UFG Price V/A	179-204	EB-2022-0200	Direct assignment by rate zone	Allocation to EGD rate zone rate classes in proportion to actual volumes. Allocation to Union rate zone rate classes in proportion to volumes consistent with the 2013 OEB approved allocation of UFG costs, updated for 2025 activity based on actual UFG gas supply purchases in 2025.
	EGI Non Commodity Related Accounts				
4	Transportation from Dawn Service D/A	179-202	EB-2022-0200	Direct assigned to the Union North rate zone	Allocation in proportion to the prescribed capacity of the Base service offering of the Transportation from Dawn service.
5	Deferral Clearing V/A	179-302	EB-2022-0200		Actual volumes
6	Parkway Delivery Obligation V/A	179-303	EB-2022-0200	Direct assignment to the Union South rate zone	2013 Dawn-Parkway firm design day demands
7	Unauthorized Overrun Non-Compliance D/A	179-304	EB-2022-0200	No 2025 balance for disposition	No 2025 balance for disposition
8	Pension & OPEB V/A	179-305	EB-2022-0200	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
9	Facility Carbon Charge V/A	179-307	EB-2022-0200	Direct assignment by rate zone	Actual volumes
10	Customer Carbon Charge V/A	179-308	EB-2022-0200	Direct assignment by rate zone	Actual volumes subject to Federal Carbon Charge
11	Carbon Charges Bad Debt D/A	179-309	EB-2022-0200	Direct assignment by rate zone	Allocation to the EGD rate zone rate classes in proportion to actual number of customers. Allocation to the Union rate zones rate classes in proportion to the allocation of Administrative & General O&M expenses.
12	Earnings Sharing Mechanism D/A	179-311	EB-2022-0200	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
13	Tax V/A	179-312	EB-2022-0200	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
14	Expansion of Natural Gas Distribution Systems V/A	179-317	O. Reg. 24/19 s.4	No 2025 balance for disposition	No 2025 balance for disposition
15	Green Button Initiative D/A	179-320	EB-2020-0183	No 2025 balance for disposition	No 2025 balance for disposition
16	Dawn Parkway Surplus Capacity D/A	179-323	EB-2022-0200	Direct assigned to the Union rate zones	Distance weighted Dawn-Parkway design day demands
17	Distribution Integrity Management Program **V**/A	179-326	EB-2022-0200		Total O&M expense excluding cost of gas
18	Post Retirement True-Up V/A	179-328	EB-2022-0200	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
19	Clean Fuel Regulation Credits D/A	179-330	EB-2022-0200		Total O&M expense excluding cost of gas
20	Indigenous Working Group D/A	179-331	EB-2022-0200		Total O&M expense excluding cost of gas
21	Cloud Computing Implementation Costs D/A	179-332	Accounting Order (003-2023)	No 2025 balance for disposition	No 2025 balance for disposition
22	Average Use V/A	179-333	EB-2022-0200	Direct assignment by rate zone	Direct assignment to General Service rate classes Rate 1, Rate 6, Rate 01, Rate 10, Rate M1 and Rate M2.
23	Getting Ontario Connected V/A	179-335	EB-2023-0143	Allocation to rate zones in proportion to 2024 actual locates	Allocation to the EGD rate zone rate classes in proportion to the allocation of 2018 system distribution operating costs. Allocation to the Union rate zones rate classes in proportion to the allocation of 2013 mains and services distribution operating costs.
24	Disposition of Property D/A	179-336	EB-2022-0200	Direct assignment by rate zone	Allocation to the EGD rate zone rate classes in proportion to 2018 Distribution Land Gross Plant. Allocation to the Union rate zones rate classes in proportion to 2013 Distribution Land Gross Plant

Enbridge Gas Inc.
Summary of Deferral and Variance Account Allocation Factors

Line No.	Account Description	Acct. No.	Reference	Allocator to Rate Zone	Allocator to Rate Class
			(a)	(b)	(c)
25	LEAP Emergency Financial Assistance D/A	179-338	EB-2023-0135	No rate zone specific allocation.	Allocation in proportion to 2025 Proposed Delivery Revenue
26	OEB Cost Assessement V/A	179-340	EB-2024-0111	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to the allocation of **2013** Administrative & General O&M expenses.
27	IRP System Pruning D/A	179-341	EB-2024-0111	Allocation to rate zones in proportion to 2018 actual rate base	Allocation to the EGD rate zone rate classes in proportion to 2018 rate base. Allocation to the Union rate zones rate classes in proportion to 2013 rate base.
28	Enbridge Sustain Affiliate Recoveries V/A	179-344	EB-2024-0111	No 2025 balance for disposition	No 2025 balance for disposition
	EGD Rate Zone Commodity Related Accounts				
29	Storage and Transportation D/A	179-88		Direct assigned to the EGD rate zone	Split of deferral balance in proportion to total Space and Deliverability cost. Allocation of Space costs to rate classes in proportion to Space allocation. Allocation of Deliverability costs to rate classes in proportion to Deliverability allocation.
	EGD Rate Zone Non Commodity Related Accounts				
30	Open Bill Extension D/A	179-325	EB-2022-0200	No 2025 balance for disposition	No 2025 balance for disposition
	Union Rate Zones Gas Supply Accounts				
31	Unabsorbed Demand Costs Variance Account	179-108		Direct assigned to the Union rate zones in proportion to UDC costs incurred	Allocation to the Union North rate zone rate classes in proportion to UDC collected in rates. Allocation to the Union South rate zone rate classes in proportion to Actual Sales Service volumes.
	Union Rate Zones Storage Accounts				
32	Short-Term Storage and Other Balancing Services	179-70		Direct assigned to the Union rate zones in proportion to Storage Excess	Allocation to the Union North rate zone rate classes in proportion to Excess Peak over Average Day demands. Allocation to the Union South rate zone rate classes in proportion to Total Design Day demands.
	EGI Accounts Not Being Requested For Clearance				
33	Incremental Capital Module D/A	179-306	EB-2022-0200		
34	IRP Operating Costs D/A	179-318	EB-2020-0091		
35	IRP Capital Costs D/A	179-319	EB-2020-0091		
36	Panhandle Region Expansion Project V/A	179-329	EB-2022-0200		
37	Site Restoration Costs Tracking Account	179-337	EB-2022-0200		
38	Asset Life Extension Costs D/A	179-343	EB-2024-0111		

Enbridge Gas Inc.
Split of EGI Account Balances to Rate Zones

Line No.	Account Description	Acct. No.	Account Balance Including Interest EGD ($000's)	Union ($000's)	Total (1) ($000's)
			(a)	(b)	(c) = (a+b)
	EGI Commodity Related Accounts				
1	Upstream Transporation Optimization V/A	179-201	(38,863.2)	2,205.9	(36,657.4)
2	UFG Volume V/A	179-203	(182.7)	11,149.6	10,966.9
3	UFG Price V/A	179-204	(4,118.1)	422.7	(3,695.4)
4	Total Commodity Related Accounts		(43,164.0)	13,778.2	(29,385.8)
	EGI Non Commodity Related Accounts				
5	Transportation from Dawn Service D/A	179-202	-	74.0	74.0
6	Deferral Clearing V/A	179-302	1,692.5	2,011.0	3,703.5
7	Parkway Delivery Obligation V/A	179-303	-	2,687.7	2,687.7
8	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-
9	Pension & OPEB V/A	179-305	(2,591.4)	(2,317.7)	(4,909.1)
10	Facility Carbon Charge V/A	179-307	(1,650.4)	808.0	(842.4)
11	Customer Carbon Charge V/A	179-308	(2.2)	-	(2.2)
12	Carbon Charges Bad Debt D/A	179-309	4,478.7	2,887.4	7,366.1
13	Earnings Sharing D/A	179-311	(13,319.8)	(11,912.8)	(25,232.7)
14	Tax V/A	179-312	(7,373.9)	(6,595.0)	(13,968.8)
15	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-
16	Green Button Initiative D/A	179-320	-	-	-
17	Dawn Parkway Surplus Capacity D/A	179-323	-	(2,365.4)	(2,365.4)
18	Distribution Integrity Management Program V/A	179-326	124.1	101.2	225.2
19	Post Retirement True-Up V/A	179-328	(27,211.9)	(24,337.4)	(51,549.2)
20	Clean Fuel Regulation Credits D/A	179-330	(20.3)	(16.6)	(36.9)
21	Indigenous Working Group D/A	179-331	154.6	126.1	280.7
22	Cloud Computing Implementation Costs D/A	179-332	-	-	-
23	Average Use V/A	179-333	7,642.6	28,982.3	36,624.963
24	Getting Ontario Connected V/A	179-335	9,127.9	5,710.4	14,838.3
24	Disposition of Property D/A	179-336	(12,202.7)	(1,290.7)	(13,493.4)
25	LEAP Emergency Financial Assistance D/A	179-338	731.6	519.8	1,251.4
26	OEB Cost Assessment V/A	179-340	1,646.4	1,472.5	3,118.9
27	IRP System Pruning D/A (2024 & 2025)	179-341	219.0	195.9	414.9
28	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-
29	Total Non Commodity Related Accounts		(38,555.2)	(3,259.1)	(41,814.3)
30					
31	Total EGI Accounts (for clearance)		(81,719.2)	10,519.1	(71,200.1)
	EGD Rate Zone Commodity Related Accounts				
32	Storage and Transportation D/A	179-88	3,403.8	-	3,403.8
33	Total Commodity Related Accounts		3,403.8	-	3,403.8
34	EGD Rate Zone Non Commodity Related Accounts				
35	Open Bill Extension D/A	179-325	-	-	-
36	Total Non Commodity Related Accounts		-	-	-
37	Total EGD Rate Zone (for clearance)		3,403.8	-	3,403.8
38	Union Rate Zones Gas Supply Accounts				
39	Unabsorbed Demand Costs Variance Account	179-108	-	5,121.9	5,121.9
40	Total Gas Supply Accounts		-	5,121.9	5,121.9
41	Union Rate Zones Storage Accounts				
42	Short-Term Storage and Other Balancing Services	179-70		(622.2)	(622.2)
43	Total Storage Accounts		-	(622.2)	(622.2)
44	Total Union Rate Zones (for clearance)		-	4,499.7	4,499.7
45	Total Deferral and Variance Accounts (for clearance)		(78,315.5)	15,018.8	(63,296.6)

Notes:
(1) Exhibit C, Tab 1, Schedule 1.

Enbridge Gas Inc.
EGD Rate Zone
Unit Rate and Type of Service

Line No.	Particulars	Sales Service (cents/m^3)	Ontario T-Service (cents/m^3)	Dawn T-Service (cents/m^3)	Western T-Service (cents/m^3)	Unbundled Service (cents/$m^{3/}$d)
		(a)	(b)	(c)	(d)	(e)
	Bundled Services:					
1	Rate 1	(0.7890)	(0.3381)	(0.3381)	(0.7890)	
2	Rate 6	(0.8111)	(0.3602)	(0.3602)	(0.8111)	
3	Rate 100	(0.7065)	(0.2556)	(0.2556)	(0.7065)	
4	Rate 110	(0.5206)	(0.0697)	(0.0697)	(0.5206)	
5	Rate 115	(0.5390)	(0.0881)	(0.0881)	(0.5390)	
6	Rate 135	(0.5284)	(0.0775)	(0.0775)	(0.5284)	
7	Rate 145	(0.5653)	(0.1144)	(0.1144)	(0.5653)	
8	Rate 170	(0.0501)	(0.0501)	(0.0501)	(0.0501)	
9	Rate 200	(0.5192)	(0.0683)	(0.0683)	(0.5192)	
	Unbundled Services:					
10	Rate 125					(0.0042)
11	Rate 300					-
12	Rate 332					(5.5398)

Enbridge Gas Inc.
EGD Rate Zone
Classification and Allocation of Deferral and Variance Account Balances

Line No.	Particulars ($000's)	Acct No.	Rate 1	Rate 6	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Rate 332	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Upstream Transportation Optimization V/A	179-201	(23,013)	(14,439)	(66)	(680)	(0)	-	(7)	(2)	-	(656)	-	-	(38,863)
2	Total Gas Supply Related Deferrals		(23,013)	(14,439)	(66)	(680)	(0)	-	(7)	(2)	-	(656)	-	-	(38,863)
3	Storage and Transportation D/A	179-88	1,787	1,503	16	41	7	-	-	(2)	11	39	-	-	3,404
4	Total Storage Related Deferrals		1,787	1,503	16	41	7	-	-	(2)	11	39	-	-	3,404
5	Transportation from Dawn Service D/A	179-202	-	-	-	-	-	-	-	-	-	-	-	-	-
6	UFG Volume V/A	179-203	(75)	(73)	(1)	(19)	(5)	-	(1)	(1)	(5)	(3)	-	-	(183)
7	UFG Price V/A	179-204	(1,694)	(1,648)	(20)	(434)	(110)	-	(20)	(20)	(104)	(69)	-	-	(4,118)
8	Deferral Clearing V/A	179-302	616	600	7	158	40	194	7	7	38	25	-	-	1,692
9	Parkway Delivery Obligation V/A	179-303	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Pension & OPEB V/A	179-305	(1,700)	(718)	(8)	(31)	(11)	(25)	(1)	(3)	(4)	(6)	-	(84)	(2,591)
12	Facility Carbon Charge Variance Account	179-307	(527)	(513)	(6)	(135)	(34)	(165)	(6)	(6)	(32)	(22)	-	(204)	(1,650)
13	Customer Carbon Charge Variance Account	179-308	(1)	(1)	(0)	(0)	(0)	-	(0)	(0)	(0)	-	-	-	(2)
14	Carbon Charges Bad Debt Deferral Account	179-309	4,146	331	0	1	0	0	0	0	0	0	-	0	4,479
15	Tax V/A	179-312	(4,837)	(2,042)	(23)	(89)	(32)	(71)	(4)	(7)	(10)	(18)	-	(239)	(7,374)
16	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Green Button Initiative D/A	179-320	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Dawn Parkway Surplus Capacity D/A	179-323	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Open Bill Extension D/A	179-325	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Distribution Integrity Management Program D/A	179-326	84	33	-	3	1	1	0	1	1	0	-	0	124
21	Post Retirement True-Up V/A	179-328	(17,851)	(7,537)	(85)	(327)	(120)	(262)	(15)	(27)	(38)	(68)	-	(883)	(27,212)
22	Clean Fuel Regulation Credits D/A	179-330	(14)	(5)	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	(0)	(20)
23	Indigenous Working Group D/A	179-331	104	41	-	3	1	2	0	1	1	0	-	0	155
24	Cloud Computing Implementation Costs D/A	179-332	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Average Use Variance Account	179-333	12,829	(5,187)	-	-	-	-	-	-	-	-	-	-	7,643
26	Getting Ontario Connected V/A	179-335	5,717	2,988	-	155	66	163	0	6	6	25	-	-	9,128
27	Disposition of Property D/A	179-336	(8,991)	(2,877)	(0)	(125)	(50)	(120)	(3)	(7)	(9)	(21)	-	-	(12,203)
28	LEAP Emergency Financial Assistance D/A	179-338	490	209	1	17	3	6	1	1	1	2	-	-	732
29	OEB Cost Assessment V/A	179-340	1,080	456	5	20	7	16	1	2	2	4	-	53	1,646
30	IRP System Pruning D/A	179-341	144	61	1	3	1	2	0	0	0	1	-	7	219
31	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Total Delivery Related Deferrals (Lines 5 through 31)		(10,478)	(15,881)	(128)	(801)	(244)	(261)	(40)	(53)	(151)	(150)	-	(1,350)	(29,536)
33	Total Storage and Delivery Disposition (line 4 + line 32)		(8,690)	(14,378)	(112)	(760)	(237)	(261)	(40)	(55)	(139)	(111)	-	(1,350)	(26,132)
34	Earnings Sharing D/A	179-311	(8,738)	(3,689)	(41)	(160)	(59)	(128)	(7)	(13)	(18)	(33)	-	(432)	(13,320)
35	Grand Total (line 2 + line 33 + line 34)		(40,440)	(32,507)	(219)	(1,600)	(295)	(389)	(55)	(70)	(158)	(800)	-	(1,782)	(78,315)

Enbridge Gas Inc.
EGD Rate Zone
Unit Rates for One-Time Adjustment - Delivery

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Bundled Services:					
1	Rate 1	(8,690)	(8,738)	(17,428)	5,154,228	(0.3381)
2	Rate 6	(14,378)	(3,689)	(18,068)	5,015,489	(0.3602)
3	Rate 100	(112)	(41)	(153)	59,993	(0.2556)
4	Rate 110	(760)	(160)	(920)	1,319,623	(0.0697)
5	Rate 115	(237)	(59)	(295)	335,399	(0.0881)
6	Rate 135	(40)	(7)	(47)	61,064	(0.0775)
7	Rate 145	(55)	(13)	(69)	59,917	(0.1144)
8	Rate 170	(139)	(18)	(158)	314,998	(0.0501)
9	Rate 200	(111)	(33)	(144)	211,220	(0.0683)
	Unbundled Services:					
10	Rate 125	(261)	(128)	(389)	9,260,357	(0.0042)
11	Rate 300	-	-	-	-	-
12	Rate 332	(1,350)	(432)	(1,782)	32,162	(5.5398)

Enbridge Gas Inc.
EGD Rate Zone
Unit Rates for One-Time Adjustment - Sales and WBT

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Bundled Services:					
1	Rate 1	(23,013)	-	(23,013)	5,103,594	(0.4509)
2	Rate 6	(14,439)	-	(14,439)	3,202,298	(0.4509)
3	Rate 100	(66)	-	(66)	14,549	(0.4509)
4	Rate 110	(680)	-	(680)	150,874	(0.4509)
5	Rate 115	(0)	-	(0)	0	(0.4509)
6	Rate 135	(7)	-	(7)	1,627	(0.4509)
7	Rate 145	(2)	-	(2)	413	(0.4509)
8	Rate 170	-	-	-	-	-
9	Rate 200	(656)	-	(656)	145,524	(0.4509)

Enbridge Gas Inc.
EGD Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 1 - Small Customer			
1	Delivery	(0.3381)	2,400	(8.12)
2	Sales & WBT	(0.4509)	2,400	(10.82)
3	Sales Service Impact			(18.94)
4	Bundled Direct Purchase Impact - OTS			(8.12)
5	Bundled Direct Purchase Impact - DTS			(8.12)
6	Bundled Direct Purchase Impact - WTS			(18.94)
	Rate 6 - Average Customer			
7	Delivery	(0.3602)	22,606	(81.43)
8	Sales & WBT	(0.4509)	22,606	(101.93)
9	Sales Service Impact			(183.37)
10	Bundled Direct Purchase Impact - OTS			(81.43)
11	Bundled Direct Purchase Impact - DTS			(81.43)
12	Bundled Direct Purchase Impact - WTS			(183.37)
	Rate 6 - Large Customer			
13	Delivery	(0.3602)	339,124	(1,221.64)
14	Sales & WBT	(0.4509)	339,124	(1,529.14)
15	Sales Service Impact			(2,750.78)
16	Bundled Direct Purchase Impact - OTS			(1,221.64)
17	Bundled Direct Purchase Impact - DTS			(1,221.64)
18	Bundled Direct Purchase Impact - WTS			(2,750.78)
19	Rate 100 - Small Customer			
20	Delivery	(0.2556)	339,188	(867)
21	Sales & WBT	(0.4509)	339,188	(1,529)
22	Sales Service Impact			(2,396)
23	Bundled Direct Purchase Impact - OTS			(867)
24	Bundled Direct Purchase Impact - DTS			(867)
25	Bundled Direct Purchase Impact - WTS			(2,396)

Enbridge Gas Inc.
EGD Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 110 - Small Customer			
26	Delivery	(0.0697)	598,568	(417)
27	Sales & WBT	(0.4509)	598,568	(2,699)
28	Sales Service Impact			(3,116)
29	Bundled Direct Purchase Impact - OTS			(417)
30	Bundled Direct Purchase Impact - DTS			(417)
31	Bundled Direct Purchase Impact - WTS			(3,116)
	Rate 110 - Large Customer			
32	Delivery	(0.0697)	9,976,121	(6,951)
33	Sales & WBT	(0.4509)	9,976,121	(44,983)
34	Sales Service Impact			(51,934)
35	Bundled Direct Purchase Impact - OTS			(6,951)
36	Bundled Direct Purchase Impact - DTS			(6,951)
37	Bundled Direct Purchase Impact - WTS			(51,934)
	Rate 115 - Small Customer			
38	Delivery	(0.0881)	4,471,609	(3,938)
39	Sales & WBT	(0.4509)	4,471,609	(20,163)
40	Sales Service Impact			(24,101)
41	Bundled Direct Purchase Impact - OTS			(3,938)
42	Bundled Direct Purchase Impact - DTS			(3,938)
43	Bundled Direct Purchase Impact - WTS			(24,101)
	Rate 125 - Average Customer			
44	Delivery Demand	(0.0042)	2,315,000	(97)
45	Unbundled Impact			(97)
	Rate 135 - Average Customer			
46	Delivery	(0.0775)	598,567	(464)
47	Sales & WBT	(0.4509)	598,567	(2,699)
48	Sales Service Impact			(3,163)
49	Bundled Direct Purchase Impact - OTS			(464)
50	Bundled Direct Purchase Impact - DTS			(464)
51	Bundled Direct Purchase Impact - WTS			(3,163)

Enbridge Gas Inc.
EGD Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 145 - Large Customer			
52	Delivery	(0.1144)	598,567	(685)
53	Sales & WBT	(0.4509)	598,567	(2,699)
54	Sales Service Impact			(3,384)
55	Bundled Direct Purchase Impact - OTS			(685)
56	Bundled Direct Purchase Impact - DTS			(685)
57	Bundled Direct Purchase Impact - WTS			(3,384)
	Rate 170 - Average Customer			
58	Delivery	(0.0501)	9,976,121	(4,997)
59	Sales & WBT	-	9,976,121	-
60	Sales Service Impact			(4,997)
61	Bundled Direct Purchase Impact - OTS			(4,997)
62	Bundled Direct Purchase Impact - DTS			(4,997)
63	Bundled Direct Purchase Impact - WTS			(4,997)
	Rate 200 - Average Customer			
64	Delivery	(0.0683)	69,832,850	(47,669)
65	Sales & WBT	(0.4509)	69,832,850	(314,882)
66	Sales Service Impact			(362,551)
67	Bundled Direct Purchase Impact - OTS			(47,669)
68	Bundled Direct Purchase Impact - DTS			(47,669)
69	Bundled Direct Purchase Impact - WTS			(362,551)

Enbridge Gas Inc.
Union Rate Zones
Unit Rate and Type of Service

Line No.	Particulars	Sales Service (cents/m^3)	Bundled DP (cents/m^3)	T-Service (cents/m^3)
		(a)	(b)	(c)
	Union North West			
1	Rate 01	(1.0044)	(1.0044)	(0.1586)
2	Rate 10	0.3921	0.3921	0.9613
3	Rate 20 - Commodity	(0.0390)	(0.0390)	(0.0390)
4	Rate 20 - Demand	(3.0491)	(3.0491)	-
5	Rate 25	(0.0347)	(0.0347)	(0.0416)
6	Rate 100	(0.0572)	(0.0572)	(0.0572)
7	Bundled-T Storage Service ($/GJ)	-	-	(0.003)
	Union North East			
8	Rate 01	(0.3310)	(0.3310)	(0.1586)
9	Rate 10	0.7009	0.7009	0.9613
10	Rate 20 - Commodity	(0.0390)	(0.0390)	(0.0390)
11	Rate 20 - Demand	(4.9700)	(4.9700)	-
12	Rate 25	(0.0427)	(0.0427)	(0.0416)
13	Rate 100	(0.0572)	(0.0572)	(0.0572)
14	Bundled-T Storage Service ($/GJ)	-	-	(0.003)
15	North T-Service Transportation from Dawn Base Service ($/GJ)	-	-	0.040
	Union South			
16	Rate M1	0.3526	0.0191	
17	Rate M2	1.0788	0.7106	
18	Rate M4	0.3251	(0.0228)	
19	Rate M5	(0.4306)	(0.6835)	
20	Rate M7	0.7024	0.0354	
21	Rate M9	0.3257	0.0284	
22	Rate T1			(0.0330)
23	Rate T2			0.0131
24	Rate T3			0.0062

Enbridge Gas Inc.
Union Rate Zones
Classification and Allocation of Deferral and Variance Account Balances

Line No.	Particulars ($000's)	Acct No.	Union North					Union South														Total
			Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	M1	M2	M4	M5A	M7	M9	T1	T2	T3	M12	M13	C1	M16	M17	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	Unabsorbed Demand Costs Variance Account	179-108	(1,203)	(166)	(57)	-	-	5,358	1,031	96	7	21	36	-	-	-	-	-	-	-	-	5,122
2	Upstream Transportation Optimization V/A	179-201	(2,393)	(880)	(371)	-	6	4,590	1,082	90	3	56	23	-	-	-	-	-	-	-	-	2,206
3	Transportation from Dawn Service D/A	179-202	-	-	49	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74
4	Total Gas Supply Related Deferrals		(3,596)	(1,046)	(379)	25	6	9,948	2,113	185	10	76	59	-	-	-	-	-	-	-	-	7,402
5	Short-Term Storage and Other Balancing Services	179-70	(85)	(24)	(13)	-	-	(194)	(73)	(33)	(0)	(18)	(3)	(14)	(148)	(16)	-	-	-	-	-	(622)
6	Total Storage Related Deferrals		(85)	(24)	(13)	-	-	(194)	(73)	(33)	(0)	(18)	(3)	(14)	(148)	(16)	-	-	-	-	-	(622)
7	Customer Carbon Charge Variance Account	179-308	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	UFG Volume V/A	179-203	122	38	17	-	13	1,015	417	186	17	295	34	120	1,464	102	4,412	9	2,822	60	6	11,150
9	UFG Price V/A	179-204	19	6	3	-	2	157	64	29	3	45	5	-	-	-	-	1	87	1	-	423
10	Deferral Clearing V/A	179-302	120	38	180	103	42	380	156	70	6	110	13	50	709	34	-	-	-	-	-	2,011
11	Parkway Delivery Obligation V/A	179-303	-	-	-	-	-	1,364	459	133	1	61	22	66	427	155	-	-	-	-	-	2,688
12	Unauthorized Overrun Non-Compliance D/A	179-304	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Pension & OPEB V/A	179-305	(414)	(64)	(45)	(35)	(12)	(905)	(137)	(34)	(29)	(12)	(2)	(24)	(104)	(14)	(481)	(0)	(4)	(1)	-	(2,318)
14	Facility Carbon Charge Variance Account	179-307	15	5	22	13	5	47	19	9	1	14	2	6	87	4	338	1	216	5	0	808
15	Customer Carbon Charge Variance Account	179-308	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Carbon Charges Bad Debt Deferral Account	179-309	581	50	43	38	17	1,464	138	51	57	14	2	37	103	11	273	0	6	0	-	2,887
16	Tax V/A	179-312	(1,179)	(182)	(129)	(99)	(35)	(2,575)	(390)	(97)	(82)	(34)	(6)	(67)	(297)	(39)	(1,368)	(1)	(12)	(2)	-	(6,595)
17	Expansion of Natural Gas Distribution Systems V/A	179-317	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Green Button Initiative D/A	179-320	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Dawn Parkway Surplus Capacity D/A	179-323	(89)	(23)	(6)	(0)	-	(136)	(46)	(13)	(0)	(6)	(2)	(7)	(42)	(15)	(1,979)	-	-	-	-	(2,365)
20	Distribution Integrity Management Program D/A	179-326	20	2	2	2	1	50	5	2	2	1	0	1	4	0	9	0	0	0	0	101
21	Post Retirement True-Up V/A	179-328	(4,350)	(670)	(475)	(366)	(130)	(9,502)	(1,440)	(358)	(304)	(125)	(24)	(248)	(1,097)	(145)	(5,050)	(3)	(45)	(6)	-	(24,337)
22	Clean Fuel Regulation Credits D/A	179-330	(3)	(0)	(0)	(0)	(0)	(8)	(1)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(1)	(0)	(0)	(0)	(0)	(17)
23	Indigenous Working Group D/A	179-331	25	2	2	2	1	63	7	2	3	1	0	2	5	0	11	0	0	0	0	126
24	Cloud Computing Implementation Costs D/A	179-332	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Average Use Variance Account	179-333	4,654	4,127	-	-	-	9,728	10,473	-	-	-	-	-	-	-	-	-	-	-	-	28,982
26	Getting Ontario Connected V/A	179-335	929	79	59	52	17	3,824	331	83	113	27	-	57	141	-	-	-	-	-	-	5,710
26	Disposition of Property D/A	179-336	(264)	(55)	(58)	(52)	(16)	(594)	(116)	(32)	(44)	(8)	-	(22)	(31)	-	-	-	-	-	-	(1,291)
27	LEAP Emergency Financial Assistance D/A	179-338	107	14	14	5	2	259	41	16	1	14	1	6	36	4						520
28	OEB Cost Assessment V/A	179-340	296	26	22	19	9	747	70	26	29	7	1	19	52	6	139	0	3	0	-	1,472
29	IRP System Pruning D/A (2024)	179-341	35	5	4	3	1	76	12	3	2	1	0	2	9	1	41	0	0	0	-	196
30	Enbridge Sustain Affiliate Recoveries V/A	179-344	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Total Delivery Related Deferrals		624	3,398	(345)	(315)	(83)	5,453	10,064	75	(222)	405	45	(1)	1,463	104	(3,658)	6	3,073	58	7	20,152
32	Total Storage and Delivery Disposition (line 6 + line 33)		539	3,374	(358)	(315)	(83)	5,259	9,991	43	(222)	387	42	(15)	1,315	88	(3,658)	6	3,073	58	7	19,530
33	Earnings Sharing D/A	179-311	(2,129)	(328)	(232)	(179)	(64)	(4,651)	(705)	(175)	(149)	(61)	(12)	(121)	(537)	(71)	(2,472)	(2)	(22)	(3)	-	(11,913)
34	Grand Total (line 4 + line 34 + line 35)		(5,187)	2,000	(970)	(470)	(141)	10,556	11,399	53	(360)	403	89	(137)	778	17	(6,130)	5	3,051	55	7	15,019

Enbridge Gas Inc.
Union Rate Zones
Allocation of Gas Supply Related Deferral Accounts by Union North East and Union North West

Line No.	Particulars ($000's)	Acct No.	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (sum b:f)
	Union North West							
	Gas Supply Related Deferrals:							
1	Unabsorbed Demand Costs Variance Account	179-108	(2,994)	(582)	(123)	-	-	(3,699)
2	Upstream Transportation Optimization V/A	179-201	650	167	69	-	8	894
3	Total Gas Supply Related Deferrals		(2,345)	(415)	(54)	-	8	(2,806)
	Storage Related Deferrals:							
4	Short-Term Storage and Other Balancing Services (1)	179-70	(24)	(6)	(1)	-	-	(32)
5	Total North West Deferral Account Disposition (Line 3 + Line 4)		(2,369)	(421)	(55)	-	8	(2,837)
	Union North East							
	Gas Supply Related Deferrals:							
6	Unabsorbed Demand Costs Variance Account	179-108	1,792	416	66	-	-	2,273
7	Upstream Transportation Optimization V/A	179-201	(3,043)	(1,047)	(440)	-	(2)	(4,532)
8	Total Gas Supply Related Deferrals		(1,251)	(631)	(374)	-	(2)	(2,258)
	Storage Related Deferrals:							
9	Short-Term Storage and Other Balancing Services (1)	179-70	(61)	(18)	(8)	-	-	(87)
10	Total North East Deferral Account Disposition (Line 8 + Line 9)		(1,312)	(649)	(382)	-	(2)	(2,345)
	Total North							
	Gas Supply Related Deferrals:							
11	Unabsorbed Demand Costs Variance Account	179-108	(1,203)	(166)	(57)	-	-	(1,426)
12	Upstream Transportation Optimization V/A	179-201	(2,393)	(880)	(371)	-	6	(3,638)
13	Total North Gas Supply Related Deferrals		(3,596)	(1,046)	(428)	-	6	(5,064)
	Storage Related Deferrals:							
14	Short-Term Storage and Other Balancing Services (1)	179-70	(85)	(24)	(9)	-	-	(118)
15	Total North Deferral Account Disposition (Line 13 + Line 14)		(3,681)	(1,070)	(437)	-	6	(5,182)

Notes:
(1) Excludes allocation to Rate 20/100 bundled storage service.

Enbridge Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Delivery

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union North					
1	Rate 01	539	(2,129)	(1,591)	1,003,149	(0.1586)
2	Rate 10	3,374	(328)	3,046	316,885	0.9613
3	Rate 20	(354)	(232)	(587)	1,505,522	(0.0390)
4	Rate 100	(315)	(179)	(495)	864,327	(0.0572)
5	Rate 25	(83)	(64)	(147)	352,194	(0.0416)
	Union South					
6	Rate M1	5,259	(4,651)	608	3,176,291	0.0191
7	Rate M2	9,991	(705)	9,286	1,306,713	0.7106
8	Rate M4	43	(175)	(133)	582,148	(0.0228)
9	Rate M5	(222)	(149)	(371)	54,243	(0.6835)
10	Rate M7	387	(61)	326	922,157	0.0354
11	Rate M9	42	(12)	30	106,247	0.0284
12	Rate T1	(15)	(121)	(137)	415,028	(0.0330)
13	Rate T2	1,315	(537)	778	5,926,779	0.0131
14	Rate T3	88	(71)	17	282,401	0.0062

Enbridge Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Commodity

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union South					
1	Rate M1	9,948	-	9,948	2,983,202	0.3335
2	Rate M2	2,113	-	2,113	573,858	0.3681
3	Rate M4	185	-	185	53,253	0.3479
4	Rate M5	10	-	10	4,148	0.2529
5	Rate M7	76	-	76	11,458	0.6671
6	Rate M9	59	-	59	19,774	0.2973

Enbridge Gas Inc.
Union Rate Zones
Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage

Line No.	Particulars	2025 Deferral Balances ($000's)	2025 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2025 Actual Volume/ Demand	Billing Units	Unit Rate (cents/m^3)
		(a)	(b)	(c) = (a + b)	(d)		(e) = (c / d) * 100
	Gas Supply Transportation Charges						
	Union North West						
1	Rate 01	(2,345)	-	(2,345)	277,189	10^3m^3	(0.8458)
2	Rate 10	(415)	-	(415)	72,948	10^3m^3	(0.5692)
3	Rate 20	(54)	-	(54)	1,764	$10^3m^3/d$	(3.0491)
4	Rate 25	8	-	8	112,058	10^3m^3	0.0069
	Union North East						
5	Rate 01	(1,251)	-	(1,251)	725,960	10^3m^3	(0.1724)
6	Rate 10	(631)	-	(631)	242,308	10^3m^3	(0.2604)
7	Rate 20	(374)	-	(374)	7,527	$10^3m^3/d$	(4.9700)
8	Rate 25	(2)	-	(2)	163,611	10^3m^3	(0.0010)
	North T-Service Transportation from Dawn						
9	Rate 20/100 Base Service ($/GJ)	74	-	74	186,720	GJ/d	0.040
	Storage Charges						
10	Rate 20/100 Storage Service ($/GJ)	(4)	-	(4)	141,504	GJ/d	(0.003)

Enbridge Gas Inc.
Union Rate Zones
Storage and Transportation Service Amounts for Disposition

Line No.	Particulars ($000's) (1)	2025 Deferral Balances (a)	2025 Earnings Sharing Mechanism (b)	Deferral Balance for Disposition (c) = (a + b)
1	Rate M12	(3,658)	(2,472)	(6,130)
2	Rate M13	6	(2)	5
3	Rate C1	3,073	(22)	3,051
4	Rate M16	58	(3)	55
5	Rate M17	7	-	7

Notes:
(1) Ex-franchise customer specific amounts determined using approved deferral account allocation methodologies.

Enbridge Gas Inc.
Union North West Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 01 - Small Customer			
1	Delivery	(0.1586)	2,200	(3.49)
2	Transportation - NW	(0.8458)	2,200	(18.61)
3	Sales Service Impact			(22.10)
4	Bundled Direct Purchase Impact			(22.10)
	Rate 10 - Average Customer			
5	Delivery	0.9613	93,000	894.00
6	Transportation - NW	(0.5692)	93,000	(529.32)
7	Sales Service Impact			364.68
8	Bundled Direct Purchase Impact			364.68
	Rate 20 - Small Customer			
9	Delivery	(0.0390)	3,000,000	(1,169)
10	Transportation Demand - NW	(3.0491)	14,000	(5,123)
11	Sales Service Impact			(6,292)
12	Bundled Direct Purchase Impact			(6,292)
	Rate 20 - Large Customer			
13	Delivery	(0.0228)	15,000,000	(3,416)
14	Transportation Demand - NW	(3.0491)	60,000	(21,954)
15	Sales Service Impact			(25,370)
16	Bundled Direct Purchase Impact			(25,370)
	Rate 25 - Average Customer			
17	Delivery	(0.0416)	2,275,000	(947)
18	Transportation - NW	0.0069	2,275,000	158
19	Sales Service Impact			(790)
20	Bundled Direct Purchase Impact			(790)
	Rate 100 - Small Customer			
21	Delivery	(0.0572)	27,000,000	(15,450)
22	Unbundled Direct Purchase Impact			(15,450)
	Rate 100 - Large Customer			
23	Delivery	(0.0572)	240,000,000	(137,332)
24	Unbundled Direct Purchase Impact			(137,332)

Enbridge Gas Inc.
Union North East Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m^3)	Annual Volume (m^3)	Bill Impact ($)
		(a)	(b)	(c)
	Rate 01 - Small Customer			
1	Delivery	(0.1586)	2,200	(3.49)
2	Transportation - NE	(0.1724)	2,200	(3.79)
3	Sales Service Impact			(7.28)
4	Bundled Direct Purchase Impact			(7.28)
	Rate 10 - Average Customer			
5	Delivery	0.9613	93,000	894.00
6	Transportation - NE	(0.2604)	93,000	(242.15)
7	Sales Service Impact			651.85
8	Bundled Direct Purchase Impact			651.85
	Rate 20 - Small Customer			
9	Delivery	(0.0390)	3,000,000	(1,169)
10	Transportation Demand - NE	(4.9700)	14,000	(8,350)
11	Sales Service Impact			(9,519)
12	Bundled Direct Purchase Impact			(9,519)
	Rate 20 - Large Customer			
13	Delivery	(0.0228)	15,000,000	(3,416)
14	Transportation Demand - NE	(4.9700)	60,000	(35,784)
15	Sales Service Impact			(39,200)
16	Bundled Direct Purchase Impact			(39,200)
	Rate 25 - Average Customer			
17	Delivery	(0.0416)	2,275,000	(947)
18	Transportation - NE	(0.0010)	2,275,000	(23)
19	Sales Service Impact			(970)
20	Bundled Direct Purchase Impact			(970)
	Rate 100 - Small Customer			
21	Delivery	(0.0572)	27,000,000	(15,450)
22	Unbundled Direct Purchase Impact			(15,450)
	Rate 100 - Large Customer			
23	Delivery	(0.0572)	240,000,000	(137,332)
24	Unbundled Direct Purchase Impact			(137,332)

Enbridge Gas Inc.
Union South Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m³) (a)	Annual Volume (m³) (b)	Bill Impact ($) (c)
	Rate M1 - Small Customer			
1	Delivery	0.0191	2,200	0.42
2	Commodity	0.3335	2,200	7.34
3	Sales Service Impact			7.76
4	Bundled Direct Purchase Impact			0.42
	Rate M2 - Average Customer			
5	Delivery	0.7106	73,000	518.76
6	Commodity	0.3681	73,000	268.74
7	Sales Service Impact			787.50
8	Bundled Direct Purchase Impact			518.76
	Rate M4 - Small Customer			
9	Delivery	(0.0228)	875,000	(199)
10	Commodity	0.3479	875,000	3,044
11	Sales Service Impact			2,845
12	Bundled Direct Purchase Impact			(199)
	Rate M4 - Large Customer			
13	Delivery	(0.0228)	12,000,000	(2,733)
14	Commodity	0.3479	12,000,000	41,745
15	Sales Service Impact			39,012
16	Bundled Direct Purchase Impact			(2,733)
	Rate M5 - Small Customer			
17	Delivery	(0.6835)	825,000	(5,639)
18	Commodity	0.2529	825,000	2,087
19	Sales Service Impact			(3,552)
20	Direct Purchase Impact			(5,639)

Enbridge Gas Inc.
Union South Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m³)	Annual Volume (m³)	Bill Impact ($)
		(a)	(b)	(c)
	Rate M5 - Large Customer			
21	Delivery	(0.6835)	6,500,000	(44,430)
22	Commodity	0.2529	6,500,000	16,441
23	Sales Service Impact			(27,988)
24	Direct Purchase Impact			(44,430)
	Rate M7 - Small Customer			
25	Delivery	0.0354	36,000,000	12,733
26	Commodity	0.6671	36,000,000	240,148
27	Sales Service Impact			252,881
28	Direct Purchase Impact			12,733
	Rate M7 - Large Customer			
29	Delivery	0.0354	52,000,000	18,392
30	Commodity	0.6671	52,000,000	346,881
31	Sales Service Impact			365,273
32	Direct Purchase Impact			18,392
	Rate M9 - Small Customer			
33	Delivery	0.0284	6,950,000	1,972
34	Commodity	0.2973	6,950,000	20,662
35	Sales Service Impact			22,634
36	Direct Purchase Impact			1,972
	Rate M9 - Large Customer			
37	Delivery	0.0284	20,178,000	5,724
38	Commodity	0.2973	20,178,000	59,990
39	Sales Service Impact			65,714
40	Direct Purchase Impact			5,724
	Rate T1 - Small Customer			
41	Delivery	(0.0330)	7,537,000	(2,485)
42	Direct Purchase Impact			(2,485)

Enbridge Gas Inc.
Union South Rate Zone
Bill Adjustment for Typical Customers

Line No.	Particulars	Deferral Unit Rate (cents/m³)	Annual Volume (m³)	Bill Impact ($)
		(a)	(b)	(c)
	Rate T1 - Average Customer			
43	Delivery	(0.0330)	11,565,938	(3,813)
44	Direct Purchase Impact			(3,813)
	Rate T1 - Large Customer			
45	Delivery	(0.0330)	25,624,080	(8,448)
46	Direct Purchase Impact			(8,448)
	Rate T2 - Small Customer			
47	Delivery	0.0131	59,256,000	7,782
48	Direct Purchase Impact			7,782
	Rate T2 - Average Customer			
49	Delivery	0.0131	197,789,850	25,974
50	Direct Purchase Impact			25,974
	Rate T2 - Large Customer			
51	Delivery	0.0131	370,089,000	48,600
52	Direct Purchase Impact			48,600
	Rate T3 - Large Customer			
53	Delivery	0.0062	272,712,000	16,825
54	Direct Purchase Impact			16,825

2025 SCORECARD RESULTS – ENBRIDGE GAS

1. The purpose of the scorecard is to measure and monitor performance of the utility. The scorecard is produced annually and includes measures in four categories: customer focus, operational effectiveness, public policy responsiveness, and financial performance. Enbridge Gas provides five years of scorecard results (2021 to 2025), at Exhibit G, Tab 1, Schedule 2.

2. For 2024, in accordance with the 2024 Rebasing Phase 2 Settlement Agreement,[1] parties agreed to the addition of new reporting metrics to be included in the OEB scorecard. The new reporting metrics will identify the in-year avoided capital costs of an investment as a result of the implementation of an "asset life extension (ALE) alternative" or "integrated resource planning (IRP) alternative", without targets set for the rate term. The purpose of these new metrics is to provide reporting and information transparency. In 2025, there were no IRP alternatives implemented. For ALE, Enbridge Gas began identifying opportunities to avoid capital costs in 2025, following the evaluation of several alternatives to mitigate high-risk pipeline segments identified after 2024 inspections. The resulting capital avoidance is expected to be reported in 2026 to align with the timing of the final mitigation decisions.

3. In 2025, Enbridge Gas met or exceeded all elements of the scorecard except for the Meter Reading Performance Measurement (MRPM).

4. The Meter Reading Performance Measurement (MRPM) metric measures the percentage of meters with no read for four consecutive months. As set out in the GDAR, the annual standard for MRPM is not to exceed 0.5% on an annual basis. The MRPM achieved for 2025 was 1.0%. The metric does not consider why Enbridge Gas has not read a meter.

[1] EB-2024-0111, Settlement Agreement, November 29, 2024.

5. Enbridge Gas is committed to the MRPM target and is taking all reasonable steps necessary to improve the metric as noted in the Assurance of Voluntary Compliance (AVC)[2]. Enbridge Gas shared its 2022 MRPM Mitigation Plan[3] with the OEB as part of Phase 1 of the 2024 Rebasing Application highlighting initiatives to improve the MRPM target. Since 2022, mitigation initiatives have included increased hiring of meter readers, reduced staff attrition, extended working hours, collaboration with meter reading vendors to conduct regular performance reviews, process improvements, advancements in meter reading technology and targeted marketing campaigns. Enbridge Gas further provided the 2024 MRPM Mitigation Plan[4] as part of Phase 2 of the 2024 Rebasing Application outlining additional strategies to improve the MRPM metric.

6. These actions have resulted in a sustained improvement in MRPM performance. The annual MRPM decreased from 4.1% in 2022 to 1.3% in 2023, 0.9% in 2024, and 1.0% in 2025. Customer complaints related to billing issues declined significantly from 1,093 in 2023 to 435 in 2024 and 312 in 2025. Enbridge Gas remains committed to continued progress through effective workforce management, enhanced customer outreach initiatives and the continued deployment of Automated Meter Reading meters and Encoder Receiver Transmitters where feasible.

7. Despite significantly improving this metric, there are ongoing challenges beyond Enbridge Gas's control that limit meter access and affect the ability to achieve this target. These include customer related access barriers such as locked gates, inside meters where tenants or landlords are unresponsive, customer sensitivity, and obstruction. In 2025, if these inaccessible meters were removed, the MRPM would have been 0.48%, in line with the targeted metric. Seasonal weather also impacts

[2] EB-2022-0188, EGI-Assurance-of-Voluntary-Compliance-20220912.pdf (oeb.ca), https://www.oeb.ca/sites/default/files/EGI-Assurance-of-Voluntary-Compliance-20220912.pdf
[3] EB-2022-0200, Exhibit 1, Tab 7, Schedule 1, pp.18-21; and Attachment 4.
[4] EB-2024-0111, Exhibit 1, Tab 7, Schedule 1, Attachment 4.

accessibility, during the winter months meter inaccessibility increases. In 2025, 53% of meters with four consecutive estimated reads occurred during winter, which in 2025 had snowfalls significantly exceeding the historical average[5]. Historically, these meters are successfully read once weather conditions improve.

8. In Phase 2 of the 2024 Rebasing Application, Enbridge Gas proposed that meters with access issues caused by or within the control of the customer be excluded from the MRPM calculation.[6] Customer behaviour impacting the number of inaccessible meters includes locked gates, inside meters with unresponsive tenants or landlords, customer sensitivity, and obstruction.[7] OEB denied this request and confirmed that the MRPM standard requiring that no more than 0.5% of active meters go without a read for four or more consecutive months remains in effect. However, the OEB granted a temporary exemption for 2025 results to provide Enbridge Gas additional time to meet the metric. Enbridge Gas continues to make efforts to achieve the 0.5% target, which remains a stretch objective given the unknown conditions caused by customer behaviour.[8]

[5] Canada's snow season turns historic as multiple cities top 500 cm - The Weather Network, https://www.theweathernetwork.com/en/news/weather/forecasts/canadas-snow-season-turns-historic-as-multiple-cities-top-500-cm
[6] EB-2024-0111, Exhibit 1, Tab 7, Schedule 1, pp.5-6.
[7] EB-2024-0111, Exhibit 1, Tab 7, Schedule 1, pp.10-13, and Attachment 3.
[8] EB-2024-0111, Decision and Order, May 29, 2025, pp. 11-12.

EGI OEB Scorecard 2021 - 2025

#	Performance Measure	Target	Actual 2025 EGI	Actual 2024 EGI	Actual 2023 EGI	Actual 2022 EGI	Actual 2021 EGI
	CUSTOMER FOCUS (Service Quality & Customer Satisfaction)						
1	**Reconnection Response Time (# of days to reconnect a customer)** (# of reconnections completed within 2 business days/# of reconnections completed)	85.0%	98.7%	99.2%	99.3%	98.1%	96.9%
2	**Scheduled appointments met on time (appointments met within designated time period)** (# of appointments met within 4hrs of the scheduled date/# of appointments scheduled in the month)	85.0%	97.2%	97.4%	96.3%	95.4%	94.5%
3	**Telephone calls answered on time (call answering service level)** (# of calls answered within 30 seconds / # of calls received)	75.0%	83.8%	85.2%	89.5%	75.9%	64.3%
4	**Customer Complaint Written Response (# of days to provide a written response)** # of complaints requiring response within 10 days / # of complaints requiring a written response	80.0%	100.0%	66.7%	100.0%	90.0%	100.0%
5	**Billing accuracy** 'The requirement states that utilities should complete manual checks of their bills to verify data when a meter read demonstrates excessively high or low usage.'		279,449 manual checks completed as per QAP	258,017 manual checks completed as per QAP	331,489 manual checks completed as per QAP	390,246 manual checks completed as per QAP	384,858 manual checks completed as per QAP
6	**Abandon Rate (# of calls abandon rate)** (# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent)	10.0%	3.9%	2.6%	1.4%	7.1%	16.0%
7	**Time to Reschedule Missed Appointments** (% of rescheduled work within 2 hours of the end of the original appointment time)	98%[1]	99.3%	98.5%	97.8%	93.8%	97.0%
#	**OPERATIONAL EFFECTIVENESS (Safety, System Reliability, Asset Management & Cost Control)**						
8	**Meter Reading Performance** # of meters with no read for 4 consecutive months / # of active meters to be read	0.5%	1.0%	0.9%	1.3%	4.1%	5.0%
9	**% of Emergency Calls Responded within One Hour** (# of emergency calls responded within 60 minutes / # of emergency calls)	90.0%	94.3%	96.0%	95.3%	94.1%	95.2%
10	**Compression Reliability** % reliable for transmission compression		99.5%	100.0%	100.0%	100.0%	99.7%
11	**Damages per 1000 locate requests**		2.21	1.91	2.10	2.31	1.95
12	**Total Cost per Customer** ($ / Customer)		762.9	756.5	745.7	683.2	643.9
13	**Total Cost per km of Distribution Pipe** ($ / km of Distribution Pipe)		19,653.3	19,492.6	19,079.6	17,480.7	16,639.6
	PUBLIC POLICY RESPONSIVENESS (Conservation & Demand Management & Connection of Renewable Generation)						
14	**Total Cumulative Cubic Meters of Natural Gas Saved (Net)** (Cumulative Lifetime Natural Gas saving) (Millions)		1665.7 [2]	2708.0 [3]	1759.6 [4]	1,385.9	1,654.9
	FINANCIAL PERFORMANCE (Avoided Capital Costs)						
15	**Integrated Resource Plan (IRP)** (Capital Cost of Facility Alternative) - (Capital Cost of IRP Alternative)		$0[5]	$0[6]	NA[7]	NA[7]	NA[7]
16	**Asset Life Extension (ALE)** (Capital Cost for Total Replacement) - (Capital Cost for Asset Life Extension)		$0[8]	$0	NA[7]	NA[7]	NA[7]
	FINANCIAL PERFORMANCE (Financial Ratios)						
17	**Current Ratio** (Current Assets / Current Liabilities)		0.56	0.61	0.92	0.84	0.71
18	**Debt Ratio** (Total Debt / Total Assets)		0.38	0.37	0.39	0.42	0.41
19	**Debt to Equity Ratio** (Total Debt / Shareholders' Equity)		0.96	0.93	0.97	1.10	1.06
20	**Interest Coverage** (EBIT / Interest Charges)		3.14	2.28	1.75	2.54	2.55
21	**Financial Statement Return on Assets** (Net Income / Total Assets)		2.66%	1.72%	1.20%	2.03%	2.07%
22	**Financial Statement Return on Equity** (Net Income / Shareholders' Equity)		6.71%	4.31%	3.00%	5.37%	5.32%

[1] Time to Reschedule Missed Appointment target was 100% prior to the Phase 1 Decision.
[2] 2025 data is draft and subject to OEB approval.
[3] 2024 is audited, and subject to OEB approval.
[4] 2023 is OEB approved and updated from last submission.
[5] There were no IRP alternatives implemented in 2025, therefore no capital costs have been avoided.
[6] There were no IRP alternatives implemented in 2024, therefore no capital costs have been avoided.
[7] Historical information is not available.
[8] There were no capital costs avoided in 2025.

ESTIMATED BILLING AND METER READING PERFORMANCE REPORT

To be filed at a later date

Integrated Resource Planning (IRP)

2025 Annual Report

May 29, 2026

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Section 1 – Introduction

This Enbridge Gas Inc. ("Enbridge Gas" or the "Company") 2025 IRP Annual Report ("Report") encompasses the period from January 1, 2025, through to December 31, 2025.

This Report complies and is consistent with the Ontario Energy Board ("OEB") Integrated Resource Planning ("IRP") Decision and Order dated July 22, 2021 ("IRP Decision") establishing an IRP Framework for Enbridge Gas ("IRP Framework"), where the OEB stated:[1]

> "Enbridge Gas shall file an annual IRP report with the OEB as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, the proceeding in which it may seek disposition of balances in the IRP Costs deferral accounts.
>
> The OEB does not intend to approve the annual IRP report, but it could impact the OEB's findings on the disposition of amounts in the IRP Costs deferral accounts or inform future proceedings.
>
> The annual IRP report and the report from the IRP Technical Working Group ("TWG") are to be filed for information regardless of whether Enbridge Gas is seeking approval to clear any balances in the IRP Costs deferral accounts.
>
> The annual IRP report should include the following information:
>
> - A summary of IRP stakeholdering activities from the past year
> - A summary of IRP engagement or consultation activities with Indigenous peoples
> - Updates on IRP pilot projects underway
> - Updates on incorporating IRP into asset management planning
> - Updates on status of potential IRP Plans
> - Updates on status of approved IRP Plans, including details of adjustments made by Enbridge Gas
> - Annual and cumulative summaries of actual peak demand reductions/energy savings generated by each IRP Plan to-date, including comparisons to the initial forecast reduction/energy savings and the actual amount of expenditure on each IRP Plan to-date
> - The most recent results of Enbridge Gas's IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of Integrated Resource Plan Alternatives ("IRPAs")
> - A summary of best available information on demand-side IRPAs, including types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions
> - Efforts taken to explore the use of interruptible rates for meeting system needs, including how customers have been provided the opportunity to consider this option
> - Any other IRP-related matters established by the OEB."

[1] EB-2020-0091, OEB Decision and Order, Appendix A, p. 22.

Section 2 – IRP Integration Update

Enbridge Gas has integrated IRP cross-functionally by embedding resources within its Asset Management ("AM"), Distribution Optimization Engineering ("DOE"), financial analysis, Customer Policy and Strategy ("CP&S"), regulatory, municipal and stakeholder engagement departments, as well as within the IRP team. These resources directly support the implementation of the IRP Decision, which includes:

- Binary screening and technical evaluations of facility projects in the Asset Management Plan ("AMP") and optimization of the AMP to include IRP Plans;
- Economic analysis of those projects with a technically feasible IRP alternative ("IRPA");
- Support for the technical and economic evaluation of enhanced targeted energy efficiency ("ETEE") and demand response ("DR") IRPAs, as well as for the design, delivery, and ongoing monitoring and evaluation of OEB-approved IRP Plans, including IRP Pilot Projects;
- Development and implementation of regional, geo-targeted and pilot-specific IRP stakeholder engagement activities, as well as an increased level of direct engagement with a number of key IRP stakeholders; and,
- Regulatory support for IRP Plans and for Leave to Construct ("LTC") proceedings.

Enbridge Gas built upon the progress made in 2024 by continuing to enhance cross-functional processes, including the following:

- **Refinement of Technical and Economic Evaluation Process for IRPAs**
  Enbridge Gas continued to develop/refine the technical and economic evaluation process in 2025, including automating data population of the technical evaluation form, evolving the documented list of key inputs and assumptions to be used in the DCF+ model and developing templates to support the economic assessments, which will help to streamline the evaluation process. This included developing templates to be used when evaluating an IRPA's economic feasibility and to improve the process of gathering, consolidating and documenting inputs from various internal departments to support the assessments. This contributed to the streamlined technical evaluation of 77 investments and supported the subsequent economic evaluation of a total of 20 investments in the Enbridge Gas AMP Addendum 2026 filed on October 30, 2025. Further details on the IRP Evaluation are outlined in Section 3.

- **Development/Refinement of ETEE Model**[2]
  Enbridge Gas refined the ETEE model that supports assessment of savings potential and costs associated with the implementation of an ETEE program. This model scales down an Ontario-wide demand-side management ("DSM") forecast to estimate DSM participation in a specific geographic region by considering the region's customer base, prior participation in DSM programs and average consumption. The model subsequently estimates the increased participation, savings and costs associated with an ETEE program in that region, incremental to the regional estimated DSM participation. This incremental ETEE data is incorporated into the DCF+ model as an input. The ETEE model was used to support the economic evaluation of the 16 investments passing the technical evaluation and for which ETEE implementation had the potential to impact project scope.

- **Implementation of IRP Pilot Projects**
  In 2025 Enbridge Gas completed the hiring for the incremental resources required to lead the design, execution and evaluation of the Southern Lake Huron Pilot Project approved by the OEB in March 2025 (EB-2022-0335). A dedicated team of four was established within the IRP department, and incremental

[2] At TWG Meeting #56 on June 25, 2025, Enbridge Gas provided a walkthrough of the ETEE model, including the key assumptions considered in the model (link – slide 30). Enbridge Gas also provided a follow-up in TWG Meeting #59 to confirm the consistency of the forecasting approach, basis of the peak to annual savings factor, and how diversification of load is considered (link).

resources were embedded within the DOE and Marketing and Customer Insights departments to execute on the Pilot Project requirements. Additionally, a resource was hired to lead the requirements for the System Pruning Pilot Project which has proceeded in accordance with the Rebasing Phase 2 Settlement Agreement (EB-2024-0111). This resource works cross-functionally across departments to execute on the requirements for the System Pruning Pilot.

Section 3 – IRPA Evaluation and AMP Update

The AMP Addendum 2026 from 2025 to 2034 was filed on October 30, 2025.[3]

Investment project scopes in the capital plan are determined through Enbridge Gas's system analysis and optimization of all traditional facility alternatives to meet the forecasted system need in the most cost-effective manner to ensure the safety, reliability and affordability of the Company's operations.

As described in the AMP, Enbridge Gas follows the Asset Investment Planning & Management ("AIPM") process to initiate the IRP assessment process of investments within the capital plan. The status of the IRP assessment for investments is provided in Appendix B of the AMP.

The IRP assessment process is detailed below:

1. **Initial Screening**
   Non-gas-carrying asset investments are screened out from the list of 2025-2034 AMP investments that would proceed to the binary screening phase.

2. **Binary Screening**
   Investments are screened out as per Section 5.2 of the IRP Framework. Investments under the Asset Class of Customer Connections are also screened out at Binary Screening stage.

3. **Technical Screening & Evaluation**
   Investments undergo an initial technical screening to determine whether a detailed technical evaluation is required.

   Investments that have passed technical screening will be evaluated for whether an investment could have a technically feasible IRPA(s). To assess the technical potential of IRPAs to meet a system need, Enbridge Gas calculates the required demand reduction and/or incremental supply by determining the difference between the required and current system capacity. Where IRPAs have the technical potential to defer, reduce or offset the required capacity through either a reduction in the design hour/day demand or incremental supply within the required timeframe, and without compromising the safety and reliability of the system, these investments pass the technical evaluation.

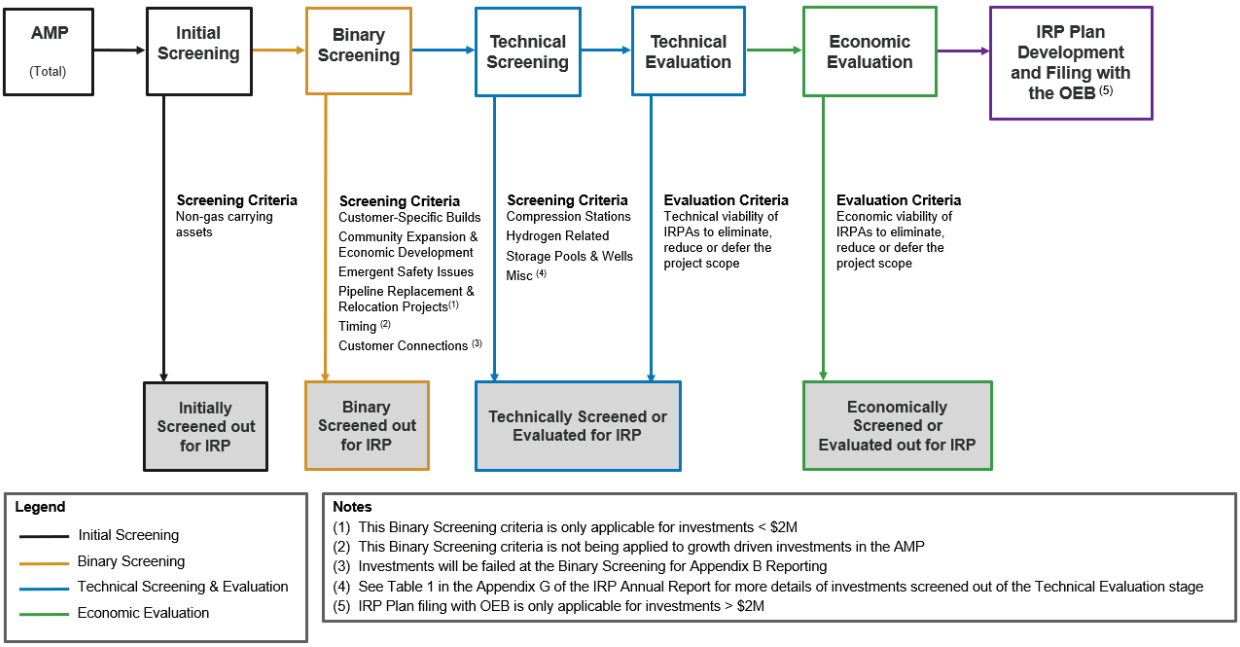
4. **Economic Evaluation**
   Investments that have passed technical evaluation are economically evaluated using the DCF+ test. The DCF+ test compares each technically feasible IRPA and the identified baseline facility project to a 'do nothing' scenario. The DCF+ results for the IRPAs and the baseline facility alternative are then compared to one another to determine the optimal alternative or combination of alternatives to meet the system need. If it is determined that the most optimal option includes one or more IRPAs, an IRP Plan will be developed where applicable.

   See Section 9 for updates on the DCF+ test used for economic evaluations. See Section 6 for Non–Pilot IRP Plan Updates.

[3] EB-2020-0091, Enbridge Gas AMP Addendum 2026, October 30, 2025 (link)

Further details on the IRP assessment screening and evaluation process can be found in Appendix F. The current IRP screening and evaluation process is outlined in Figure 3.1.

Figure 3.1 – IRP Assessment Process



2025 IRP Assessment Update

Enbridge Gas continually evolves its system models to improve the modelling methodology. This includes gathering and considering newly available and relevant information, data, and insights. This ensures that Enbridge Gas' system models reflect the best available information regarding Ontario's projected future demand for natural gas.

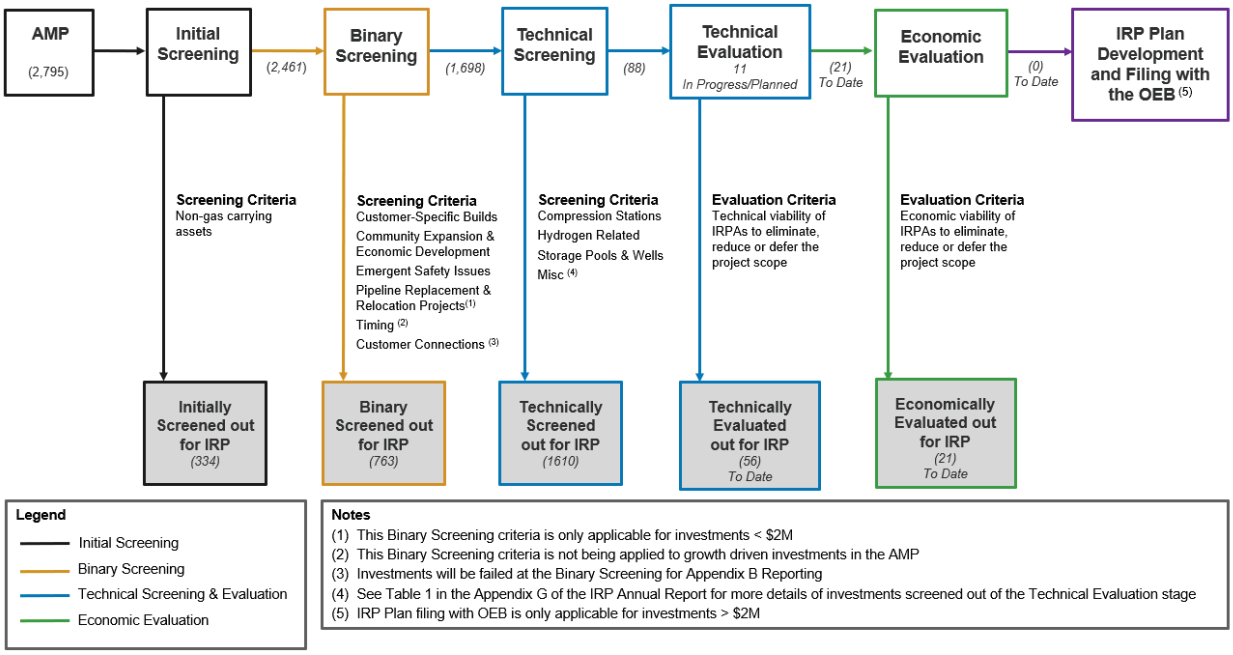
The 10-year forecast for the 2025-2034 AMP Appendix B incorporates the following key factors:

1. System Reinforcement Plan ("SRP") Update
    - A refresh to the SRP was completed in Q1 2025. The process included an update to the customer connection forecast, updates to customer load, new connections and new proposals with actuals, and updated customer load values for new customers.

2. Energy Policy and Market ("EP&M") Adjustments
    - As summarized in Enbridge Gas's 2024 Rebasing Application (EB-2022-0200), Enbridge Gas introduced adjustments to its demand forecasts (for existing customers, customer additions and average annual use) and design elements (design hour and design day) to account for potential changes to natural gas demand in the 10-year forecast period. These demand forecasts and design elements are routinely used in various business planning processes such as the SRP, AMP, Gas Supply Plan, etc. The adjustments are based on external factors related to policy signals (federal/provincial/municipal), market trends (builder and consumer preferences) and stakeholder feedback (customer, municipal and Indigenous). Annually Enbridge Gas will review and update, as needed, the adjustments to account for new and/or updated external signals and/or development.

A summary of the number of investments at each stage of the IRP screening and evaluation process is outlined in Figure 3.2

Figure 3.2 – Overview of IRP Evaluation Results – 2025-2034 AMP



In 2025, Enbridge Gas completed the IRP screening and evaluation of all investments in the AMP that had a defined scope. A summary of the IRP screening and evaluation process on the 2,795 investments in the AMP Addendum 2026 is provided below:

- 334 investments were screened out using initial screening.
- 763 investments were screened out using binary screening.
- 1610 investments were screened out using technical screening.
- 77 investments underwent a complete technical evaluation, including all investments under the Asset Class of Growth and Distribution Pipe.
    - 56 investments did not pass technical evaluation.
    - 21 investments passed technical evaluation.
- 11 investments remain to undergo technical evaluation or have the evaluation currently in progress as of the time of filing.
    - 5 investments under the Asset Class of Transmission Pipe & Underground Storage have an IRP evaluation status of “In-Progress”. Due to the broad scope and scale of these investments, supply-side alternatives have a significant potential for technical feasibility but are inherently responsive to market conditions, and therefore, will be assessed closer to the forecasted in-service date. The assessment of demand-side alternatives is currently in progress. The corresponding IRP evaluation and results will be included in either an LTC application or IRP Plan.
    - 3 investments in the EDIMP have a technical evaluation status of “In Progress” and are awaiting further integrity assessment to confirm project scope and timing. The IRP evaluation will proceed once project scope and timing has been established. Based on the status of the integrity assessments, Enbridge Gas anticipates IRP evaluation will be conducted later in 2026.
    - 3 Investments under the Asset Class of Growth have an IRP evaluation stage of “In Progress” and are currently being rescoped. IRP evaluation will resume once the revised scope is confirmed.

- 21 investments passed the technical evaluation, where 20 have undergone an economic evaluation. There is 1 investment under the Asset Class of Growth for the IRP pilot project that is not applicable for economic evaluation.
    - 20 investments failed economic evaluation for an IRPA to be an optimal alternative.
        - 4 investments under the Asset Class of Growth with an in-service date ("ISD") of 2025 or 2026. The facility alternative has been identified as the optimal solution and will be implemented accordingly.
        - 10 investments under the Asset Class of Growth with an ISD of 2028 and beyond. The facility alternative has been identified as the optimal solution, and the project scope will be monitored. Annual review of the facility and IRP alternatives will be conducted to confirm the optimal solution prior to alternative implementation. Contract customer engagement within the area of benefit, where applicable, will be conducted closer to the forecasted ISD.
        - 6 investments under the Asset Class of Distribution Pipe with an ISD of 2028 and beyond. The facility alternative has been identified as the optimal solution, and the project scope will be monitored. Annual review of the facility and IRP alternatives will be conducted to confirm the optimal solution prior to alternative implementation. Contract customer engagement within the area of benefit, where applicable, will be conducted closer to the forecasted ISD.

Enbridge Gas has provided a high-level breakdown of the investments screened or evaluated out of the AMP Addendum 2026 for IRP including the associated 2025-2034 Forecast in Appendix C.

Section 4 – IRP Pilot Project Update

Southern Lake Huron Pilot Project

On March 27, 2025, the OEB issued its Decision and Order approving the Southern Lake Huron ("SLH") Pilot Project scope, contents, costs, and proposed accounting treatment of costs as filed by Enbridge Gas, subject to the various changes as detailed in the Decision and Order ("Pilot Decision").[4] The key changes in the Pilot Decision related to the delivery of the SLH Pilot Project are to:

- Reject funding for advanced gas technologies, namely hybrid heating, natural gas heat pumps and natural gas thermal energy storage. Recognizing that thermal energy storage can utilize electricity, the pilot funding was approved for thermal energy storage, on the condition that it utilizes electricity and does not require or incent the customer to install, modify, or upgrade gas-fired space heating or water heating equipment.
- Reallocate the funding for the denied advanced gas technologies (hybrid heating and gas heat pumps) to the budget for Limited Electrification Measures. Enbridge Gas was directed to increase the number of participants for its electrification offerings.
- Collect and include in the pilot's Evaluation, Measurement & Verification ("EM&V") plans the weather normalized gas consumption data from the estimated 320 customers that have Encoder Receiver Transmitter ("ERT") technology and cold climate air source heat pumps ("ccASHP") and compare this to their weather normalized gas consumption before the heat pumps were installed, to the extent that the data is available. Enbridge Gas was also directed to include the weather normalized consumption data from a representative sample of those customers in the SLH Pilot Project study area with the ERT technology who have not installed heat pumps.

On the same date, the OEB issued a Notice of Review on the OEB's own motion (EB-2025-0124), initiating a proceeding to review the Pilot Decision in respect of three questions relating to the findings on electricity IRPAs and the exclusion of funding for gas-fired technologies.

On April 15, 2025, Enbridge Gas filed a letter to the OEB to request clarification and expansion of the scope of the pending Review Motion. This letter outlined that Enbridge Gas does not believe that it is appropriate to proceed with the aspects of the proposal that are subject to the OEB's Review Motion. The letter requested that the OEB indicate that the following aspects of the Pilot Decision are stayed or suspended pending the outcome of the Review Motion: the direction to reallocate the IRP Pilot budget related to natural gas-based technologies to the expansion of electric solutions, any aspect of the Pilot Decision that purports to amend the IRP Framework and/or DSM Framework, the direction to analyze and develop potential additional IRP pilot projects, and the direction to consult with the IRP TWG on such potential opportunities.

On April 22, 2025, in response to a letter submitted by Pollution Probe, Enbridge Gas filed a letter confirming the Company was proceeding with the implementation of the IRP Pilot Project including the electrification measures at the limited participation levels proposed by Enbridge Gas in the Pilot Application. The stay request that specifically relates to the IRP Pilot Project is only in relation to the direction in the Pilot Decision to redirect funds relating to advanced natural gas technologies to electrification IRPAs as that item is clearly at issue in the Review Motion. Furthermore, Enbridge Gas confirmed that it will not include any advanced natural gas technology IRPAs (including thermal energy storage) without further direction from the OEB.

On July 4, 2025, Enbridge Gas filed its 2024 IRP Annual Report.[5] Within it, Enbridge Gas fulfilled the direction in the Pilot Decision to include a detailed Pilot project plan. The SLH Pilot Program Design and Implementation Plan ("SLH

---

[4] As per the OEB Decision on the IRP Pilot Project, Enbridge Gas engaged with the IRP Technical Working Group ("TWG") to file an updated detailed project plan and estimated unit rate, and bill impact associated with the forecast 2025 pilot costs for typical customers by rate class in the 2024 IRP Annual Report. See EB-2025-0155, 2024 Utility Earnings and Disposition of Deferral & Variance Account, Exhibit G, Tab 2, Schedule 1

[5] EB-2025-0064 Exhibit I.1.13-ED-4 Attachment 1

project plan") included all approved offers (ETEE offers, Limited Electrification offer, Demand Response offer) but not the Advanced Gas Technology offer at issue in the Review Motion. As directed, Enbridge Gas engaged with the IRP TWG to develop the SLH project plan and update it on a rolling basis.

On December 11, 2025, the OEB issued a decision indicating that it will not proceed on its own Review Motion as it did not consider the review to result in the most just, expeditious and efficient determination of the matters before the OEB. The OEB noted that the questions raised are best considered in the context of a broader review of IRP policies but acknowledged that its conclusion does not necessarily extend to a different review motion filed by a different party.

On December 22, 2025, Enbridge Gas filed its own Notice of Motion to Review (EB-2025-0333) requesting the following variation of the Pilot Decision:

- Approve the inclusion of advanced gas technologies in the SLH IRP Pilot Project;
- Remove the direction to re-allocate the budget for the denied advanced gas technologies to electrification measures;
- Remove or correct the broader statements in the Pilot Decision supporting the determination not to approve initiatives that would result in the adoption of gas fired appliances and continue the use of natural gas; and,
- Remove the direction to consult with the IRP TWG on a second IRP pilot project on specified proposed measures, pending further direction from the current and ongoing EB-2025-0125 IRP Framework Review.

On May 14, 2026, the OEB issued its Decision on the Motion to Review.[6] The OEB did not vary its original Decision to reject incentives for advanced gas technologies in the SLH Pilot Project. However, the OEB clarified that this component of the Decision is specific to the SLH Pilot Project. The role of gas technologies as IRP alternatives in IRP is a matter that can be addressed in the broader IRP Framework Review and the OEB does not consider the Decision in the SLH Pilot Project to have predetermined or prejudged the outcome of that proceeding. The OEB did vary the original Decision by not requiring reallocation of the $1.5 million advanced gas technologies budget to electrification measures. The Decision also found that it 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. Matters related to a second IRP pilot project and any further IRP pilot projects will be addressed as part of the IRP Framework Review.

SLH Pilot Program Design and Implementation Updates

Enbridge Gas launched the SLH Pilot offers as described in the SLH project plan under the name "Sarnia Saves" on the following dates:

- July 31, 2025. Commercial and Industrial Custom Offer[7]
- September 22, 2025. Residential Whole Home Offer[8]
- September 22, 2025. Residential Single Measure Attic Insulation Offer
- September 22, 2025. Residential Limited Electrification Offer
- October 8, 2025. Commercial and Industrial Direct Install Offer
- October 8, 2025. Commercial and Industrial Prescriptive Downstream Offer
- February 20, 2026. Residential Demand Response Offer

The OEB's Pilot Decision states that the detailed SLH project plan should be updated on a rolling basis. The following section identifies the changes made to the design, delivery, marketing, stakeholdering, and EM&V efforts relative to

[6] EB-2022-0333, OEB Decision and Order, May 14, 2026.
[7] The Sarnia Saves website for all SLH IRP Pilot commercial offers is accessible at www.enbridgegas.com/sarniasaves/business
[8] The Sarnia Saves website for all SLH IRP Pilot residential offers is accessible at www.enbridgegas.com/sarniasaves

the sections of the SLH project plan filed in the 2024 IRP Annual Report as Appendix H.[9] All other elements of the SLH project plan remain unchanged.

i. SLH Project Plan pilot area update

Section of Plan	As filed	Change	Justification
Overview (2024 IRP Annual Report, Appendix H, pp. 241)	• City of Sarnia and Village of Point Edward (N7S, N7T, N7V, N7W, N7X) • Brights Grove (N0N 1C0)	The pilot area was clarified by adding highway boundaries • City of Sarnia and Village of Point Edward (postal codes starting with N7S, N7T, N7V, N7W, N7X) that are north of Highway 25 and west of Highway 26 and Brights Grove (N0N 1C0)	Ensures consistency with the pilot area in the Pilot Project application.

ii. SLH Project Plan Offer updates

Commercial, Industrial Direct Install and Prescriptive Offers

Section of Plan	As filed	Change	Justification
Table 4 – SLH Pilot Direct Install Incentive Structure by Measure (2024 IRP Annual Report, Appendix H, pp. 247) Table 7 – SLH Pilot Prescriptive Downstream Incentive Structure by Measure (2024 IRP Annual Report, Appendix H, pp. 252)	Each measure has a unique maximum equipment and installation incentive.	Measures are no longer subject to specific equipment and installation incentive maximums. Measures are eligible to receive 100% of relevant project costs (equipment and installation), up to $100,000 per project.	This change was made to simplify the “free upgrade” messaging and promote the installation of larger more complex projects.
Commercial Direct Install offer – Delivery Approach (2024 IRP Annual Report, Appendix H, pp. 248)	The delivery agent will recruit and onboard local trade allies, coordinate outreach efforts, identify opportunities, connect customers with these trade allies, and provide support throughout the process from engagement to equipment installation.	The delivery agent will continue with these activities, but Enbridge Gas has expanded the recruitment of trade allies by leveraging its existing DSM trade ally relationships.	Expanding recruitment efforts has helped onboard more trade allies faster and facilitated the generation of more project leads.

[9] EB-2025-0064 Exhibit I.1.13-ED-4 Attachment 1

Commercial and Industrial Custom Offer

There were no changes to the IRP Pilot Commercial and Industrial custom offer's design, delivery or incentive structure outlined in the SLH project plan.

Residential Whole Home Offer

Section of Plan	As filed	Change	Justification
Table 13 – SLH Pilot Residential Whole Home Incentive Structure by Measure (2024 IRP Annual Report, Appendix H, pp. 263)	Incentive offered for Windows/Doors/Skylights/Sliding Doors is $50 per rough opening	Incentive offered for Windows/ Doors/ Skylights/ Sliding Doors was updated to $100 per rough opening	As noted in the SLH project plan, Pilot incentive amounts will be updated to remain consistent with the in-field DSM offer.

Residential Single Measure Attic Insulation Offer

There were no changes to the IRP Pilot Residential Single Measure Attic Insulation Offer's design, delivery or incentive structure outlined in the SLH project plan.

Residential Limited Electrification Offer

Section of Plan	As filed	Change	Justification
Table 19 – Key Features of the SLH Pilot Electrification Offer (2024 IRP Annual Report, Appendix H, pp. 270)	Offer requires customers to fully switch from natural gas space heating to electricity after the heat pump installation without any back up natural gas space heating options. Participants do not need to disconnect their natural gas service.	An exception to this eligibility criteria was made that allows participants to keep natural gas fireplaces.	This exception was made after consultation with the TWG.[10] Enbridge Gas and the TWG member who raised this exception agreed that even if a natural gas fireplace is kept, most peak demand reduction benefits would likely still be achieved.
Table 19 – Key Features of the SLH Pilot Electrification Offer (2024 IRP Annual Report, Appendix H, pp. 270)	N/A	A new participation restriction was added. If a customer receives an incentive for an electric cold climate air source heat pump ("ccASHP") or electric ground source heat pump ("GSHP") through the SLH Pilot Electrification Offer,	This new participation restriction was added after consultation with the TWG.[11] TWG members agreed that if a participant were to get a heat pump, it would be counterintuitive for Enbridge Gas to also pay for the participant's building envelope improvements

[10] IRP TWG Meeting Notes, Meeting #55, (link)
[11] IRP TWG Meeting Notes, Meeting #60, (link), IRP TWG Meeting Notes, Meeting #55, (link)

		they cannot also participate in the SLH Pilot Residential Whole Home or SLH Pilot Residential Single Measure offer	because there is no added gas peak load reduction. Enbridge Gas agreed and added this new restriction.

Residential Demand Response Offer

Section of Plan	As filed	Change	Justification
Incentive Structure (2024 IRP Annual Report, Appendix H, pp. 274)	"Bonus" Participation Incentive: For each heating season that participants remain enrolled in the program and meet eligibility requirements, participants will enter a draw for a chance to win $2000.	The "bonus" participation incentive was reframed as an annual participation incentive. It was also changed to be a $20 annual incentive rather than a chance to win $2000.	Enbridge Gas's Demand Response delivery agent recommended the shift in incentive to $20 offered to all participants to align with incentive best practices. The incentive level was set to align with the IESO Peak Perks incentive for simplicity for the market.
Incentive Structure (2024 IRP Annual Report, Appendix H, pp. 274)	"Bonus" Participation Incentive eligibility requirements include participation in at least 50% of DR event hours each heating season.	For the 2025/2026 heating season, participants will get $20 if they enroll in the program by March 30, 2026. There is no requirement to participate in at least 50% of DR event hours for that heating season. The requirement to participate in at least 50% of DR event hours to receive the $20 incentive remains in effect for the 2026/2027 heating season.	The 50% participation requirement was removed for the 2025/2026 heating season to simplify and maximize first time signups into this new Enbridge Gas offer.

iii. SLH Project Plan Marketing Updates

Residential Marketing Tactics Updates (2024 IRP Annual Report, Appendix H, pp. 275)

Tactic	Objectives	Description	Status
Residential ETEE offers – Pre-launch			
SLH pilot residential webpage	Awareness and method of applying to residential offers	The webpage acts as a hub for SLH pilot residential offers. All residential marketing tactics drive customers here to learn more about the offers and sign up.	Completed September 8th, 2025
Community photo and video shoot	Awareness	A custom image and video shoot captured local community footage and reaction to pilot design features.	Launched on September 16, 2025, to December 30, 2026. Active on YouTube and program landing page.

Residential ETEE offers – Post-launch			
Customer-facing brochures for all ETEE pilot residential offers	Awareness	The customer-facing brochure highlights all pilot residential offers and outlines incentive amounts, pilot features, and specific calls to action.	Completed October 8, 2025
Direct Mail focusing on launch of ETEE pilot residential offers	Awareness and collection of engagement data	Direct mail was sent to approximately 25,000 residential customers to introduce the pilot residential offers, and outline incentive amounts, pilot features and specific call to action.	Completed October 15, 2025
Direct mail — follow-up postcard	Awareness and collection of engagement data	The postcard was meant to reinforce the direct mail campaign	The postcard was not needed. The intent of the postcard was to boost early leads into the residential pilot offers. Early marketing generated a large number of leads into the residential pilot offers. To prevent a backup of processing customers into the pilot, the postcard was not sent.
Eblasts (x3) promoting pilot ETEE residential offers	Awareness and collection of engagement data	Targeted emails promoted all pilot residential offers.	An eblast was sent to residential customers in the pilot project area on September 25, 2025, with a follow-up on October 2, 2025. Early marketing generated a large number of leads into the residential pilot offers. To prevent a backup of processing customers into the pilot, a third eblast was not sent in 2025.
Google Search	Awareness and collection of engagement data	The Google search campaign promoted the pilot offers to Google users searching for energy rebate information.	Launched September 23, 2025, to March 9, 2026
Digital campaign (Summer and Fall)	Awareness and collection of engagement data	Digital marketing tactics were implemented to target the local population, utilizing platforms such as Google and Meta.	Launched from September 21 to December 1, 2025.
Radio	Awareness	Two 30 second spots were run for approximately 5 weeks to promote the residential offers.	Launched from September 22 to November 15, 2025.

Out of home (OOH) marketing campaign	Awareness	Geo-targeted marketing targeted commuters, drivers and walking traffic. Tactics included transit shelters, bus advertisements, and digital screens.	Launched from September 22 to November 15, 2025.
Print ads	Awareness	Local newspaper advertisement was meant to promote pilot offers.	Early marketing generated a large number of leads into the residential pilot offers. To prevent a backup of processing customers into the pilot, print ads were not run in 2025.
Events	Awareness	Events will be attended by Enbridge Gas staff or pilot delivery agents to promote the offers, and distribute printed marketing material.	The pilot will have a presence at the 2026 Sarnia Home Show on April 10, 2026. Enbridge Gas continues to explore other events to promote the residential pilot offers.
Scam awareness eblast	Awareness	An email awareness campaign was sent to residential customers in the pilot area warning against unauthorized and illegitimate third parties posing as Sarnia Saves.	Completed February 4, 2026
Residential Demand Response			
Demand Response webpage[12]	Awareness, collection of engagement data and directing customers to the third-party microsite	The webpage promotes the Demand Response offer and directs customers to the third-party microsite	Completed February 20, 2026
Demand Response third-party microsite[13]	Awareness, collection of engagement data and enrollment process	The third-party microsite is run by the Demand Response delivery agent EnergyHUB. It is required to manage enrollment, incentive payments and Demand Response events	Completed February 20, 2026
Eblast promoting Demand Response	Awareness and collection of engagement data	Targeted emails promoting the Demand Response offer.	Completed February 27, 2026
Google search campaign	Awareness and collection of engagement data	The Google Search campaign will run for 17 weeks, maintaining sustained visibility among customers actively searching for smart	Starting February 27, 2026

[12] https://www.enbridgegas.com/ontario/sarnia-saves/smart-rewards/
[13] https://greatergrid.com/enroll/programs/thermostats/enbridge-gas/

		thermostat–related offers and incentives	
Digital marketing campaign	Awareness and collection of engagement data	Demand Generation and Meta campaigns will run for 10 weeks, leveraging audience targeting to reach eligible customers in the pilot region and reinforce awareness	Starting February 27, 2026
Direct in-app promotion to smart thermostats in the pilot region	Awareness and directing customers to the third-party microsite	Device Partners (Amazon, Google Nest, Honeywell, Ecobee etc.) will promote Demand Response to customers in pilot area with a Partner-brand smart thermostat.	Late February and early March 2026
Device Partner eblasts	Awareness and directing customers to the third-party microsite	Device partners will send an email to promote Demand Response to customers in pilot area with a Partner-brand smart thermostat.	Late February and early March 2026

Commercial Marketing Tactics Updates (2024 IRP Annual Report, Appendix H, pp. 277 and pp. 279)

The original plan presented Small Business ("SMB") and Commercial/Industrial ("CI") customers as distinct segments. This was revised by combining marketing to these groups. Combined marketing simplified the approach to market and customer participation, and made it easier to communicate a complete picture of all pilot commercial offers.

Segmentation remained where it helped target messaging to specific audiences. This included having separate direct mail material for restaurants and general commercial customers, and separate LinkedIn campaigns for small and large commercial customers.

Commercial Marketing Tactics

Tactic	Objectives	Description	Status
Commercial offers – Pre-launch			
SLH pilot commercial webpage	Awareness and method of applying into commercial offers	The webpage acts as a hub for SLH pilot commercial offers. All commercial marketing tactics drive customers here to learn more about the offers and sign up.	Completed on September 8, 2025
Community photo and video shoot	Awareness	A custom image and video shoot captured local community footage for use in marketing material.	Completed September 16, 2025
Customer-facing brochures and Sales sell-	Awareness	The customer-facing brochure and sell sheet highlight all pilot commercial offers and outline	Completed on September 8, 2025

sheet for all pilot commercial offers		incentive amounts, pilot features, and specific call to action.	
Commercial offers – Post-launch			
Direct Mail focusing on launch of pilot commercial offers	Awareness	Direct mail was sent to promote the commercial pilot offers. Two versions were prepared – one for restaurant and food services with Demand Control Kitchen Ventilation (DCKV) information, and another for general businesses.	Completed October 15, 2025
LinkedIn Digital campaign	Awareness and collecting engagement data	LinkedIn campaign targeted professionals and businesses interested in rebates, energy efficiency, and sustainability.	Launched October 10 to December 3, 2025
Events	Awareness	Events will be attended by Enbridge Gas staff or pilot delivery agents to promote the offers, and distribute printed marketing material.	Enbridge Gas participated in two events to present attendees with the details of the commercial pilot offers: • Sarnia-Lambton Leadership Legacy Summit (Oct 22, 2025) • Sarnia Lambton Chamber of Commerce Business Showcase (Nov 19, 2025)
Eblasts x 2	Awareness and collecting engagement data	Targeted emails promoted all pilot commercial offers.	Completed on October 8 and December 4, 2025

iv. SLH Project Plan Stakeholder Engagement Activities – progress on engagement items listed in the filed plan (2024 IRP Annual Report, Appendix H, pp. 280)

Engagement items	Objectives	Description	Status
Pre-launch			
Detailed stakeholder lists	Coordination, Awareness	Develop detailed stakeholder contact lists for Tier 1-3 entities[14]	Complete
Briefing collateral	Awareness	Build briefing material toolkit for Tier 1, 2 priority audiences	Complete
External communications collateral	Awareness	Develop communications collateral to be used by Tier 1, 2 priority audiences across their community-facing channels to support broad public awareness	Complete
Advance notifications of Pilot launch to select stakeholders	Engagement; Awareness	Notify key municipal (elected and staff-side), Indigenous, MPP/MP constituency stakeholders about the Pilot; provide campaign overview	Complete
Launch			
Conduct priority stakeholder briefings	Awareness, information sharing	Tier 1, 2 priority briefings to occur (in advance of launch of marketing campaign where possible); capture feedback	Complete
Pilot launch event	Awareness	Execute a launch event with local-area stakeholders (supported by media materials)	Rather than a launch event, Enbridge Gas executed individual briefings with stakeholders in advance of marketing launch and leveraged individual/ organizational awareness channels. Enbridge Gas also participated in two post-launch events to present attendees with the details of the pilot offers: • Sarnia-Lambton Leadership Legacy Summit (Oct 22, 2025) • Sarnia Lambton Chamber of Commerce Business Showcase (Nov 19, 2025)

[14] Tier 1-3 reflects the mapping of stakeholders outlined in the Stakeholder Mapping section of the filed Pilot delivery Plan. Stakeholder groups are prioritized into three tiers based on their ability to influence the uptake and outcome of the Pilot.

Sustained engagement	Awareness	Tier 3 briefings to generate interest, awareness, information sharing across channels; capture feedback	Complete
Channel amplification	Awareness	Encourage Tier 1-3 stakeholders to promote the Pilot through organic owned/ earned channels (e.g. social, newsletters, e-blasts) Create additional lift around milestone activities (e.g. back to school planning)	Residential and Commercial ETEE offers were promoted in local groups including: • Online article in Living in Lambton • Village of Point Edward CiviKit • Bluewater Power Energy Conservation site • Sarnia Lambton Economic Partnership emails and Facebook promotion
Visibility with Tier 3 community	Awareness	Work with local business associations, chambers, identify speaking opportunities to address members and leverage respective engagement channels	Complete, inclusive of the two post-launch events noted above. Ongoing for 2026
Additional (Fall) media push	Awareness; uptake	Drive seasonal messaging through media and public-facing channels; leverage case studies, testimonials	Complete, inclusive of channel amplification examples above. Ongoing for 2026
Post-launch			
Sustainment activities	Awareness, information sharing	Ongoing touchpoints with the municipality, and Tier 1-3 stakeholders to ensure they remain engaged around the Pilot's progress, issues, and next steps. This phase will be supplemented by additional media activations to support marketing/ consumer-facing activities.	Ongoing
Webinars	Awareness, information sharing	The SLH pilot offers were presented as part of four regional IRP webinars delivered by Enbridge Gas	Completed December 2025 and January 2026

v. SLH Project Plan Objective 1 EM&V Plan and Activities (2024 IRP Annual Report, Appendix H, pp. 287)

Enbridge Gas hired Dunsky Energy + Climate Advisors ("Dunsky") through an RFQ process to evaluate the peak hour demand changes for Objective 1. The IRP TWG was engaged for their input on the plan, and it was finalized in Q1 2026. The objectives, methodology, and evaluation timelines are summarized below from the EM&V plan. See Appendix G for the detailed plan.

Evaluation Objectives

The evaluation focuses on enabling Enbridge Gas to develop a clear understanding of how ETEE and DR programs impact system peak hour demand.[15] Specifically, the evaluation will:

- Quantify actual peak-hour flow reductions (m^3/h) from ETEE and DR by comparing pre- and post-program load by customer type.
- Assess DR event performance, including the reliability, magnitude, and persistence of customer response.
- Identify factors that influence achieved impacts (weather, building characteristics, measure types).
- Extrapolate observed impacts to design-hour conditions using Enbridge Gas's regression methods.

These findings will support future IRP Plans by improving assumptions, refining modeling techniques, and informing the feasibility of using demand-side IRPAs in lieu of traditional system reinforcement projects.

Evaluation Methodology

The evaluation applies a set of coordinated analytical approaches to estimate program impacts.

- Load-vs-temperature regression to measure normalized pre/post load changes and validate Enbridge Gas's regression approach.
- Participant vs non-participant comparisons using hourly interval meter data.
- DR event analysis using smart thermostat telemetry matched to consumption records.
- Impact disaggregation by customer type and measure where statistically reliable.
- Load curve analysis to examine peak shifting, rebound effects, and system-level peak relief.

As part of this approach, customer demand extrapolation will be led by Enbridge Gas, with Dunsky providing methodological review and collaboration. This collaborative approach enables the evaluation to leverage Enbridge Gas's expertise in system design, demand profiling, and historic Ontario design-day practice, while also incorporating Dunsky's experience in DR, regression-based load modeling, and large dataset evaluation.

All analyses will incorporate rigorous data validation and transparency regarding uncertainty levels, underlying assumptions, and extrapolation techniques. The evaluation relies on hourly meter data, weather data (temperature, wind), smart thermostat event records, and program tracking datasets.

[15] The baseline used to estimate system impacts is pre-ETEE hourly consumption data, which is analyzed using regression methods and compared against post-intervention conditions. This approach is described in the EM&V report (Section 7.6.3).

vi. SLH Project Plan Objective 2 EM&V Plan and Activities (2024 IRP Annual Report, Appendix H, pp. 290)

The timing of Pilot Objective 2 activities was shifted to align with pilot offer launch dates. In some cases, the cadence of activities was also changed as described in the table below. The approach to Objective 2 activities is consistent with the filed plan.

Updated timeline and cadence of Objective 2 evaluation plan activities (2024 IRP Annual Report, Appendix H, pp. 300 and pp. 314)

Activity	Cadence	Fieldings To-Date	Next Fielding	Notes
Evaluation plan	Complete – Filed in Pilot project plan			
Program & peer research	Once	Nov 2025	Q1 2026	A jurisdictional scan of North American DR programs was completed in November 2025.
Enbridge staff interviews	Quarterly	July 2025; Jan 2026	April 2026	
Res/Com Delivery Agent interviews	Quarterly	Dec 2025	Feb 2026	Surveys were upgraded to interviews to get better details on delivery agent responses
Res/Com Contractor & Energy Advisor interviews	Quarterly	Jan 2026	April 2026	Surveys were upgraded to interviews to get better details on contractor responses. Residential Energy Advisors interviews were added.
Broad-based Residential/ Commercial Surveys	Annually	Sept 2025	Fall 2026	The DSM broad-based participant surveys were expanded to include non-participants. Cadence was updated from quarterly to annual. Annual cadence avoids over-surveying the customer base and is sufficient to gather baseline data
ETEE Pilot Participant Interviews	Quarterly	Jan/Feb 2026	April 2026	Timing for participant interviews shifted to ensure there was enough participation in the Pilot from which to pull a sample
ETEE Participant Surveys	Quarterly	NA	Q2 2026	Timing for participant surveys shifted to ensure there was enough participation in the Pilot from which to pull a sample
DR Participant Surveys	Twice	NA	Q2 2026	
ETEE Near-Participant Surveys	Twice	NA	Q2 2026	Cadence was updated from quarterly to twice. This cadence is sufficient to gather the data needed
DR Opt-Out Surveys	Twice	NA	Q2 2026	
ETEE/DR Non-Participant Surveys	Once	NA	Q1 2027	The cadence has shifted from twice to once. Non-participation in pilot offers can only be confirmed after the pilot has ended.
Cost Analysis	Twice	NA	Q2 2026	
Quarterly memos	Quarterly	Nov 2025	Q1 2026	
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

System Pruning Pilot Project

In the Rebasing Phase 1 Decision, the OEB provided the following commentary on IRP alternatives to address potential stranded asset risk relating to system renewal activities through the consideration of system pruning;

> "System pruning, for example, converting a subdivision from natural gas to electricity for space and water heating, is another option. Under this option, existing gas customers would replace their gas equipment with electric equipment. This could be supported by an IRP solution, which would consider various alternatives to avoid the need to replace the facilities. The IRP process could offer alternatives through pilot projects for the OEB to consider, including incentives to be paid to the customers to defray the cost of replacing their gas equipment, or investment by the utility to cover the cost of the electric equipment to be recovered over time, with a return on that investment."[16]

In the Company's submission for Phase 2 of its 2024 Rebasing Application, Enbridge Gas confirmed it is committed to working with the IRP TWG and other relevant stakeholders to consult on system pruning processes. It was also proposed that a jurisdictional scan be completed to identify how utilities in other jurisdictions are approaching natural gas system pruning to identify best practices, where applicable.[17]

In the Settlement Proposal for Phase 2 of the Company's 2024 Rebasing Application, all parties agreed that Enbridge Gas would develop and implement a system pruning pilot project. Specifically, Enbridge Gas would develop its approach to system pruning in consultation with the IRP TWG by the end of Q2 2025 and begin implementation on one or two pilots by the end of Q1 2026. Additionally, the Parties agreed 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 TWG. Further, the parties agreed that a new IRP System Pruning Deferral Account with a $5 million cap would 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 request OEB approval through an IRP Plan application.[18] The OEB accepted the Settlement Proposal on November 29, 2024.[19]

In Q1 2025, Enbridge Gas consulted with the IRP TWG on the system pruning workplan and draft scope of work for the system pruning jurisdictional scan. OEB Staff confirmed a subcommittee of the IRP TWG ("TWG Subgroup") would be established for detailed consultation on the jurisdictional scan and pilot approach.

Enbridge Gas developed a workplan on the key elements required for the System Pruning pilot approach to meet the Q2 2025 deliverable, identifying the timing as to when elements would be brought forward to the TWG Subgroup for input and feedback, and when they would be shared with the full TWG to ensure alignment. With the provincial election occurring in February, consultation activities were put on pause during the writ period between January 31 to March 19, 2025, which impacted the timing of consultation with the TWG Subgroup on specific elements. Enbridge Gas continued to provide informational updates during this period, however discussion on items was deferred until consultation and cost-award eligibility were reinstated by OEB Staff. Following the end of the writ period, Enbridge Gas continued to engage with the TWG Subgroup and full TWG to finalize the approach and confirm support by the end of June 2025 for the System Pruning approach elements.[20] On July 4, 2025, Enbridge Gas filed its 2024 IRP Annual Report, with the System Pruning approach filed as Appendix G.[21]

In parallel to the development of the approach, DNV was engaged to conduct a jurisdictional scan on behalf of Enbridge Gas and the IRP TWG. A subcommittee of the IRP TWG was established for detailed consultation on the

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[16] EB-2022-0200, Phase 1 Decision and Order, December 21, 2023, p. 52
[17] EB-2024-0111. Phase 2, Exhibit 1, Tab 17, Schedule 1, April 26, 2024, p.17-27
[18] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1 Schedule 1, November 4, 2024, p.20-21.
[19] EB-2024-0111, Decision on Settlement Proposal and Interim Rate Order, November 29, 2024.
[20] Engage with Us, OEB (link) System Pruning Subgroup Meetings #2, 3, 4 (January 12, 2025, March 20, 2025, April 17, 2025), TWG Meetings #50 (March 26, 2025), Meeting #52 (April 23, 2025), Meeting #53 (May 7,2025), Meeting #54 (May 21, 2025), Meeting #55 (June 4, 2025), Meeting #56 (June 25, 2025).
[21] EB-2025-0064 Exhibit I.1.13-ED-4 Attachment 1

jurisdictional scan and approach. The scan was completed on August 15, 2025.[22] The purpose of this study was to better understand and gain insights into how gas utilities among North American and European jurisdictions are approaching pruning to their gas distribution pipelines, where informative to the Ontario context. The study was intended to provide a foundational understanding of system pruning approaches, best practices and lessons learned to assist in the development of pilots in Ontario. While the full jurisdictional scan report results were not available as the system pruning approach was being developed, as DNV was a participant in meetings of the system pruning TWG Subgroup and full TWG, input was provided in relation to the jurisdictional scan work in progress. The scan covered six utilities/jurisdictions – five were selected as they have planned or undertaken system pruning or non-pipeline activities, and one was selected because of their successful collaboration activities amongst their gas and electric utilities within that jurisdiction. Of the six studied jurisdictions, only two (California and New York) have completed actual system pruning projects. The study found that system pruning is a utility action in its infancy. "Among the reviewed jurisdictions, the primary driver of system pruning or Non-Pipeline Alternative (NPA) activities is a policy framework centered around climate and equity. Although considerations about system cost is a concern, it was not explicitly cited as the driver to policies that promote system pruning and NPAs."[23]

2025 Project Implementation Update

Following the TWG's support of the System Pruning approach in July 2025, implementation of the pilot began in Q3 2025, which included the following activities:

- **Contractor Engagement**
  Enbridge Gas engaged a contractor to serve as the delivery agent for the System Pruning Pilot. The Home Inspectors Group was selected through a Request for Proposal process which, amongst other criteria, sought contractors that were knowledgeable and unbiased about natural gas and electric equipment and appliances.

- **Pilot Candidate Selection**
  Enbridge Gas conducted an initial pre-screen with customers that met the selection criteria outlined in the Approach. This preliminary outreach provided information on the pilot and a pre-screen form for customers to express their interest level in participating in the pilot. Based on the results of the pre-screen, the contractor then initiated discussions with customers who had indicated that they were "Definitely Likely" to participate in the pilot, had confirmed they consent to Enbridge Gas sharing their contact information with the contractor to proceed to the next step and are the last customer at the end of a natural gas main (meaning that their disconnection would allow for decommissioning of their service and the associated main to their home, thus avoiding the eventual replacement of that portion of main and their service). Learnings from these "Definitely Likely" customers will inform next steps.

- **Electric Local Distribution Company ("LDC") Engagement**
  Enbridge Gas met with two LDCs to understand their processes and perspectives as they relate to the System Pruning pilot. Discussions with these LDCs included:
  - The degree to which system constraints are localized and can only be determined once specific addresses for pilot candidates are known
  - The fact that the LDCs are resource-constrained and would not be able to support prioritization of candidates based on network capacity
  - The standard processes that would be followed (and varied as required) should customer(s) convert off of natural gas

[22] Engage with us, OEB (link)
[23] DNV, System Pruning Jurisdictional Scan – Final Report (August 15, 2025), Key Findings section.

- How customers would contribute if network enhancements were required to support their conversion off of natural gas.
- The standard assumptions LDCs consider for subdivision planning, inclusive of natural gas for space and water heating

As implementation continues, engagement through these processes will be incorporated into the work of the contractor with the customer.

Enbridge Gas has continued to update and consult with the TWG on key elements of the pilot implementation.[24]

[24] Engage with us, OEB (link), IRP TWG Meeting #57 (July 30, 2025), Meeting #61 (December 3, 2025)

Section 5 – IRP Stakeholder and Indigenous Engagement Update

As part of the OEB's IRP Decision, the OEB determined that "the three components of Enbridge Gas's proposed Stakeholder Engagement Process will provide valuable input into Enbridge Gas's IRP activities and shall be incorporated in the IRP Framework. The three-component process includes: gathering of stakeholder engagement data and insight, stakeholder days, and targeted engagement. The OEB also directed the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholder efforts".[25]

Regional Engagement

Enbridge Gas conducted four regional webinars from December 2025 through January 2026. The format, which was previously delivered through multiple region-specific sessions, was revised to a single session offered on multiple days to provide flexibility for participants. Invitations to the webinar were sent to individuals subscribed to IRP updates, with a more targeted emphasis on those involved in energy and infrastructure planning, such as municipal staff and planners, community leaders, technical professionals, IESO Integrated Regional Resource Plan working group members, regulatory or policy representatives, along with others interested in the assessment and implementation of non-pipeline alternatives. This updated approach supported a broader review of the IRP evaluation results, including the key learnings from the process and the determination that no specific regional projects were identified to proceed with an IRP alternative.

The webinars covered topics including an overview of IRP and the assessment process along with updates on the AMP Addendum 2026, regional projects and IRP pilot projects. Each session concluded with a Question-and-Answer segment and information on how to stay engaged, including sharing feedback via the IRP mailbox. The total attendance across the four webinars was 51 participants. An additional 11 stakeholders not able to attend a session requested the webinar recording from Enbridge Gas.

During each session, attendees were encouraged to view the IRP webpage for additional information and opt-in to the mailing list to receive future email updates on project information and upcoming events. The feedback and responses shared during the webinars have been documented and shared on the IRP webpage, along with copies of the presentation deck and webinar recording.[26]

Following the webinars, an IRP newsletter was issued to IRP subscribers, and provided a summary of the regional webinars and pilot updates, with information on how to engage the IRP team and remain engaged.[27]

Municipal Engagement

Enbridge Gas engages with a wide cross-section of municipal audiences and stakeholders on an ongoing basis through a dedicated Municipal and Stakeholder Engagement (MSE) team, including at regional and province-wide municipal conferences as part of engagement on IRP within existing stakeholder engagement channels:

- ROMA (Rural Ontario Municipal Association) – January 2025
- NOMA (Northwestern Ontario Municipal Association) – April 2025
- OSUM (Ontario Small Urban Municipalities) – May 2025
- NODSA (Northern Ontario Service Deliverers Association) – June 2025
- AMO (Association of Municipalities) – August 2025
- OEMC (Ontario East Municipal Conference) – September 2025
- WOWC (Western Ontario Wardens Caucus) – October 2025

Additionally, Enbridge Gas participates in 50+ local events and symposiums throughout the year with local chambers of commerce, boards of trade, associations, and municipalities (e.g. the City of Toronto's Community Environment Days). During

[25] EB-2020-0091, IRP Proposal OEB Decision and Order, July 22, 2021, p. 66.
[26] Regional Planning & Engagement | Enbridge Gas
[27] Integrated Resource Planning (IRP) 2025 Newsletter

these conferences and events, dedicated members of the MSE team are on-hand to engage directly with attendees and answer questions related to IRP and IRP pilots (including ways to remain engaged). The relationships and contacts established at these forums support the development of the targeted IRP distribution list to ensure that dedicated municipal leads and subject matter experts can be engaged for regional stakeholder activities and targeted engagement where applicable.

Costs for exhibiting at conferences and events on an ongoing basis, such as booth costs, are not attributed to IRP as they represent an opportunity to leverage existing channels. Costs for events that are specific to an IRP initiative, such as the Chamber of Commerce Business Showcase noted in the SLH Project Plan Stakeholder Engagement Activities, are attributed to IRP, with Chamber of Commerce Business Showcase expenditures allocated to the SLH Pilot Project.

Targeted / Project-Specific Engagement

Enbridge Gas has proactively initiated engagement activities with local distribution companies (LDCs) in areas of high growth that could trigger an LTC project as part of the Company's approach regarding coordinated energy system planning. The purpose of these engagements is to develop understanding of each sector's planning approaches, share and discuss the basis for each sector's demand forecasts and, for Enbridge Gas, to determine if there is a need to adjust the Company's demand forecast and system design based on the shared information. Additionally, these engagement activities establish communication channels with LDCs which can support future information sharing and discussion. While a formal coordination framework has not yet been established, these engagements have resulted in meaningful discussion and collaboration between the gas and electricity sectors. This work is intended to enhance the comparability and clarity of key planning inputs and to support more effective coordination going forward. Enbridge Gas will continue to monitor the OEB's implementation of the Minister's Directive related to the government's Integrated Energy Plan.

Additionally, when applicable, Enbridge Gas implements a Non-Binding Expression of Interest (EOI) / Reverse Open Season (ROS) process to gather potential additional customer demands and identify opportunities to reduce existing contract customer demands, which ensures that the best available customer demand information informs project requirements and potential IRP opportunities. An EOI/ROS is triggered on a case-by-case basis for increased demand-driven LTC projects, and for defined geographic areas of benefit where Enbridge Gas contract rate customers have identified a need for increased or decreased capacity via their regular ongoing discussions with their Enbridge Gas account managers. IRP relevant questions have been embedded within the EOI/ROS form, including:

- Customer's interest in converting existing firm distribution service to interruptible distribution service if the ability to negotiate lower than posted interruptible rates was available.
- Customer's consideration of energy conservation activities in their bid amounts and existing demand and the customer's interest in considering additional energy conservation activities as it relates to reduction in contract bids or existing demand. This process will involve additional engagement with specific contract customers to discuss on-going DSM energy efficiency projects, as well as whether there are incremental opportunities for IRP alternatives, to ensure that the bid put forward is inclusive of consideration of both DSM and IRP.

Further details on project specific consultation are described in Section 6.

IRP Pilot Project

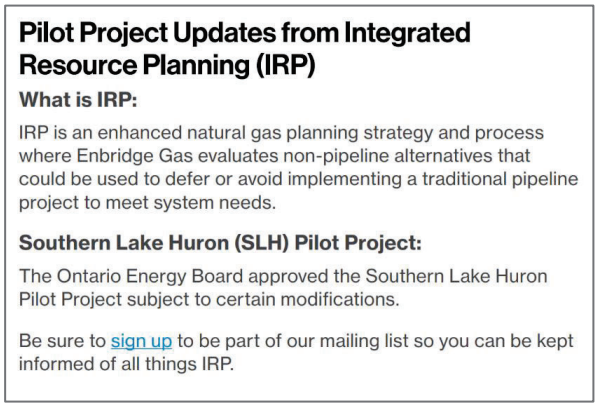
For the IRP Pilot Project, Enbridge Gas conducted stakeholder engagement with the local municipalities, municipal agencies, business associations, LDC, IESO and the local community to provide an overview of the pilot and to garner feedback on the proposed IRP alternatives in support of the initial filing of the application in 2023 and 2024. Refer to Section 4, of the Southern Lake Pilot Project for the stakeholder engagement conducted in 2025.

Indigenous Engagement

IRP has continued to provide Enbridge Gas's Indigenous Engagement team with informational materials for use during informal discussions, and during their normal course of engagements to highlight the Regional Engagement sessions and to promote registrations for engagement events that may be happening in their areas. This included incorporating IRP updates and the latest developments on the pilot projects within the summer edition of the Indigenous newsletter, Figure 5.5.

Additionally, contact details to address any further questions or to promote registration for updates were sent out by the Indigenous advisor for each region.

Figure 5.5 – Excerpt of the IRP section in the 2025 Indigenous newsletter



Pilot Project Updates from Integrated Resource Planning (IRP)

What is IRP:

IRP is an enhanced natural gas planning strategy and process where Enbridge Gas evaluates non-pipeline alternatives that could be used to defer or avoid implementing a traditional pipeline project to meet system needs.

Southern Lake Huron (SLH) Pilot Project:

The Ontario Energy Board approved the Southern Lake Huron Pilot Project subject to certain modifications.

Be sure to sign up to be part of our mailing list so you can be kept informed of all things IRP.

IRP was also discussed as part of the Indigenous Working Group ("IWG"), in response to a recommendation in The Brattle Group report that led to the suggestion that IRP be added as a standing item to the IWG agenda.[28] Enbridge Gas IRP staff participated in two IWG meetings on March 4 and July 15, 2025. The IWG meeting dated March 4 included a brief discussion on IRP activities, the IRP pilots, and IRP stakeholder activities, as well as a discussion item raised by Enbridge Gas on the potential for an IWG standing IRP agenda item to engage on future IRP activities and discussion. Enbridge Gas also advised that the Indigenous Nations, serviced by Enbridge Gas, received the information on the IRP webinars through their Community and Indigenous Engagement Advisor.

Additionally, a member of the IWG advised there was no Indigenous participation on the IRP TWG led by OEB staff, and suggested Enbridge Gas and the IWG jointly ask the OEB to be involved in the group. Enbridge Gas conveyed the request to OEB Staff in March 2025 and provided the IWG contact to OEB staff so they can discuss the request.

At the July 15, 2025 meeting Enbridge Gas discussed IRP and asked for member feedback on the best process to engage the IWG moving forward, as well as on the initial priority areas of focus for engagement. It was suggested by an IWG member that a smaller sub-group be established going forward to discuss IRP and the IWG and Enbridge Gas agreed on this approach. There was also a discussion on the engagement process and objectives for the Southern Lake Huron Pilot Project. Following the meeting Enbridge Gas shared the Pilot Project Application identifying the section outlining Indigenous group engagement and asked IWG members to indicate their interest in joining an IRP sub-group. Enbridge Gas subsequently sought input from the interested members on what topics would be of interest for discussion; however, no responses were received.

As such, at the November 26, 2025 IWG meeting, Enbridge Gas suggested removing IRP as a standing agenda item and that IRP be discussed at future meetings as requested. The IWG agreed. Additionally, where Enbridge Gas identifies IRP alternative opportunities that would include First Nations communities in the area of benefit, it would seek to work with First Nations in the development of its detailed approach, including through the IWG.

[28] The Brattle Group Report Recommendations, EB-2025-10-30, EB-2025-0155, Exhibit G, Tab 3, Schedule 1, Page 6 and Page 34 of 49

Section 6 – Non–Pilot IRP Plan Updates

IRP Plans will be developed for projects with technically and economically feasible IRPAs, where the IRPA is determined to be the preferred alternative to address a system need. This section provides an update on the status of IRP Plans in-flight and in development in 2025.

In 2025, Enbridge Gas completed the IRP screening and evaluation of all investments in the AMP that had a defined scope. At the economic evaluation stage, no potential IRP alternatives were identified as the optimal solution and the facility alternative was the solution in the best interests of Enbridge Gas and its customers to address the system need. Consequently, Enbridge Gas did not file any non-Pilot IRP Plan applications with the OEB.

Enbridge Gas will be monitoring the project scopes and annual review of the facility and IRP alternatives will be conducted to confirm the optimal solution prior to alternative implementation. Additionally, contract customer engagement within the area of benefit, where applicable, will be conducted closer to the forecasted in-service date. Table 6.1 summarizes the IRPA implemented since 2022.

Table 6.1 – Summary of IRP Solutions Implemented

Project Name	Project Description	IRP Alternative Identified	IRP Implementation Status	Facility Cost vs. IRPA Cost	IRP Implementation Outcome
East Kingston Creekford Reinforcement	Installation of 6.2km of NPS 8	Demand-side IRPA – contract demand turnback Supply Side IRPA –CNG	Completed	Forecasted facility cost = $24.3M Supply-side IRPA (CNG) cost = $0.6M	CNG was procured for the winters of 2022/2023 and 2023/2024, where the CNG agreement provided time for Enbridge Gas to implement a contract turnback to reduce contract demand and in turn avoid the facility project. The turnback was confirmed by the Contract Customer on November 11, 2022. This capacity was sufficient to defer the reinforcement; however, it was not received in time to avoid a CNG contract back-up solution.[29]

[29] EB-2023-0092, Exhibit C, Tab 1, June 14, 2023, p.20-25.

Section 7 – Integrated Resource Planning Alternatives Update

In its Decision and Order establishing an IRP Framework for Enbridge Gas, the OEB found that a "document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report."[30]

To provide an overview of the types of alternatives considered when addressing system needs, a summary of traditional facility alternatives, alongside the non-pipeline IRP alternatives, has been included in Table 7.1.

Enbridge Gas routinely evaluates traditional facility alternatives, where applicable, as part of project scoping to ensure the optimal alternative is reflected in the AMP. Enbridge Gas also incorporates forecast gas supply contracts into the development of the AMP. These contracts may influence the timing of transmission projects and, by providing firm supply at known transmission locations, may have the potential to avoid or reduce the need for new infrastructure. Enbridge Gas designs transmission facility requirements to integrate these firm deliveries.

IRP alternatives are assessed after the consideration of traditional facility alternatives and are evaluated against the established project scope in the AMP. Given the dynamic nature of facility planning and the evolving demand forecast, the assessment process can be iterative. Project scopes for both traditional facility and IRP alternatives are periodically reassessed to ensure up to date information is captured.

Table 7.1 - Summary of Facility and IRP Alternatives

Traditional Facility Alternatives	Loop existing pipeline (system reinforcement)
	Replace existing pipeline with a larger pipeline (system reinforcement)
	Install a new pipeline (with consideration for different routes)
	Add / upgrade stations serving system area
	Increasing system pressure (when applicable)
	Add compression to increase pipeline capacity (when applicable)
Supply-side IRP Alternatives	Compressed Natural Gas (CNG) / Liquefied Natural Gas (LNG)
	Market-based supply
Demand-side IRP Alternatives	Enhanced Targeted Energy Efficiency (ETEE)
	Demand Response (DR)
	Electrification Measures (specific to the pilot projects) *

* As part of the first-generation IRP Framework, the OEB determined that it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs. However, a limited number of electrification measures are included in the Southern Lake Huron pilot project and System Pruning pilot.

[30] EB-2020-0091, IRP Planning OEB Decision and Order, July 22, 2021, p. 36

Appendix B: Integrated Resource Planning Alternatives provides additional information on both demand-side and supply-side IRP alternatives including “types of IRPAs, estimates of cost, peak demand savings, status in Ontario, the potential role and relevance to Enbridge Gas’s system, and learnings from pilot projects and other jurisdictions.”

Enbridge Gas expects the IRP pilot projects to provide additional information to refine and update the impacts of the IRP alternatives identified.

Section 8 – Technical Working Group Summary

In the IRP Decision, the OEB directed that an IRP TWG be established and led by OEB staff, to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

All documents and presentations concerning the IRP TWG can be found on the OEB website.[31]

Attached in Appendix E: Technical Working Group Report is a report prepared by the IRP TWG.

[31] Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)

Section 9 – DCF+ Methodology Update

In the IRP Decision, the OEB concluded that the DCF+ test should be the economic evaluation test used under the IRP Framework. Further, within its IRP Decision, the OEB recognized that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs and clarify how these costs and benefits should be considered within the DCF+ test. The OEB directed Enbridge Gas to study the IRP DCF+ test and encouraged consultation with the TWG, which includes representatives from Enbridge Gas, OEB staff, and non-utility members.[32] Below is a summary of the key topics discussed in 2025 and the resulting outcomes that informed the economic evaluation of IRPAs, particularly in light of changes to the federal fuel charge.

On March 15, 2025, the Government of Canada enacted regulations with an effective date of April 1, 2025, to set the value of the federal fuel charge to $0 and to remove the requirement for provinces and territories to have a consumer-facing carbon price. In response to these changes, Enbridge Gas updated the enhanced DCF+ test to reflect the zeroing of the federal fuel charge and removal of the consumer-facing fuel charge rates.

At the March 19, 2025, TWG meeting, Enbridge Gas discussed the refinements to the DCF+ as outlined in its written responses provided to the TWG on January 16, 2025. In these refinements, Enbridge Gas confirmed that the DCF+ would follow a nominal approach in which revenues would be escalated in accordance with the approved price cap index (PCI) escalator, costs would reflect the best forecast available or reflect a 2% inflation in the absence of a forecast, and that the weighted average cost of capital (WACC) would remain at a nominal rate. TWG members were supportive of the proposed changes, as they agreed it aligned the costs and discount rate appropriately. The changes also served to address concerns regarding additivity of Phase 1 and Phase 2. TWG members remained concerned, however, about the additivity of Phase 3, as they said Phase 3 includes benefits calculated using the GDP multiplier, and that this multiplier accounts for incremental economic activity which is distinct from project-specific costs and benefits that are included in Phase 1 and Phase 2. In response, Enbridge Gas noted that they would present Phase 1 and Phase 2 separately and additively, and present Phase 3 independently.

Members of the TWG also noted that the social cost of carbon is a distinct cost that should be reflected in Phase 3. They expressed concern that setting the consumer carbon cost to zero could understate carbon-related impacts and that presenting Phase 3 separately may further de-emphasize those impacts. In addition, members of the TWG suggested exploring other non-energy benefits (NEBs), like employment impacts, in addition to GDP multipliers.

Reliability was raised as a topic requiring further discussion, particularly whether it should be included in the DCF+ test or separately as an additional consideration. Enbridge Gas noted that reliability is already reflected in the IRP alternative design considerations. Members also suggested quantifying the cost of service interruption associated with different options.

At the March 26, 2025, TWG Meeting, Enbridge Gas presented its DCF+ test results, incorporating the nominal adjustments it had described in the March 19, 2025, TWG meeting. Enbridge Gas outlined its proposed approach to identifying the most cost-effective alternative, which was to augment consideration of DCF+ Phase 1 results with the sum of DCF+ Phase 1 and Phase 2 results – and then prioritize the alternative with the highest combined net present value (“NPV”). Enbridge Gas noted that this approach optimized investment value while minimizing costs to all customers. To enhance efficiency, Enbridge Gas also discussed a potential threshold approach under which a sensitivity analysis would only be conducted for projects where the NPV differential is less than the absolute cost of lowest-cost alternative.

Discussion continued in the April 9, 2025, meeting, with TWG members’ feedback focused on the proposed sensitivity threshold and sensitivity analysis applied to the updated economic test results that now reflected the zeroing of the federal fuel charge. In particular, the change in fuel charge prompted TWG members to consider whether the DCF+ test remained the appropriate starting point for assessing IRPAs, or whether an alternative

[32] EB-2020-0091, IRP Planning OEB Decision and Order, July 22, 2021, p. 56-57.

approach could better support productive discussion and consensus-building where agreement was not reached (e.g. how to assess economic development and job impacts, and whether rate impacts or broader customer impact should be prioritized). Enbridge Gas continues to agree with the OEB's decision on the IRP Framework that the three-phase DCF+ is the economic evaluation to be used for IRP as it appropriately reflects the costs and benefits to ratepayers, participants, and society, with particular focus on rate impacts. The decision confirms that the test "best aligns with the goal and purpose of IRP planning, which is to address the system needs of Enbridge Gas's regulated operations and identify and implement the solution that is in the best interest of Enbridge Gas and its customers."[33] The fuel charge is only one input among the costs and benefits included in the test. Changing the value of an input, in accordance with prevailing policy, is not an appropriate basis for challenging the methodology. Enbridge Gas and other TWG members acknowledged that despite remaining differences, meaningful progress has been made in refining some aspects of the DCF+ through multi-year TWG consultation.

With respect to the mechanics of the DCF+ calculation, a TWG member suggested a secondary criterion to the sensitivity threshold that would identify the magnitude of cost reduction required for each alternative to achieve NPV parity with the preferred alternative. TWG members also noted the need for considerations beyond the combined Phase 1 and Phase 2 results, including whether Phase 2 results should be weighted given the IRP Framework's emphasis on rate impacts as assessed in Phase 1. In its review of Phase 3, Enbridge Gas confirmed that the fuel charge rate was set to $0 in accordance with the zeroing of the customer-facing federal fuel charge and that no alternative valuation of carbon could be incorporated into the economic test. Enbridge Gas asserted that the pricing of carbon should be aligned with government legislation and policy in all aspects of the calculation. TWG members agree with this approach for Phase 1 and 2, but expressed concerns with applying this approach to Phase 3 of the DCF+ since the purpose of Phase 3 is to reflect societal costs that are not reflected in Phases 1 and 2.

At the July 30, 2025 TWG meeting, Enbridge Gas presented DCF+ results for several new projects, incorporating additional considerations to support alternative selection. These considerations included identification of the lowest cost alternative and associated bill impacts, the alternative with the highest Phase 1 NPV, the alternative with the highest combined Phase 1 + Phase 2 NPV, and the projected demand profile over time. Based on the assessment of project cost, Phase 1 NPV and combined Phase 1 and 2 NPV, and the persistence and trajectory of demand[34], Enbridge Gas identified whether projects would be slated to proceed with the facility alternative or continue to be monitored for changes in forecast demand. Four projects were identified to proceed as a facility alternative and were included in the AMP Addendum 2026.

In the review of the alternatives' economic analyses, the TWG members reiterated concerns regarding not quantifying the social carbon costs in Phase 3. In addition, one TWG member noted that the Phase 3 multipliers used do not provide an accurate measure of impacts on jobs and the broader economy. Enbridge Gas restated its position that (1) the DCF+ test should include economic costs and benefits, consistent with OEB's jurisdiction and government policy, and (2) the GDP multiplier reflects the quantifiable flow of economic spending across sectors and is, therefore, an appropriate measure of these benefits. In this meeting Enbridge Gas and the TWG concluded that extensive consultation had been conducted on DCF+ test enhancements, that the positions of parties were well understood and that these positions have been considered. It was, therefore, determined that there was not value in having further discussion on the DCF+ test, and that any further discussion regarding the DCF+ methodology would be best had as part of a proceeding. Enbridge Gas will bring forward its application of the DCF+ methodology through the IRP Framework review and Implementation Plan.

[33] EB-2020-0091, OEB Decision and Order, Enbridge Gas Inc. Integrated Resource Planning, July 22, 2021, p. 56.
[34] See Appendix F for more detail on the economic evaluation approach and selection considerations as part of the overall screening process.

Section 10 – IRP Planning for 2026

This section provides a high-level summary of the work streams that Enbridge Gas expects to build upon and evolve further in 2026. These work streams are continuations of the work done in 2025.

External Stakeholder Outreach

Enbridge Gas will continue with its external stakeholder efforts including ongoing engagement with municipalities through existing stakeholder engagement relationships, as opportunities to engage on IRP and further develop targeted stakeholder lists.

Enbridge Gas will schedule regional or general stakeholder engagement sessions to support broader understanding of IRP and its process, provide updates on the IRP evaluations on the latest AMP and ongoing IRP initiatives. Feedback received from these stakeholder engagement sessions will be reviewed and considered for subsequent stakeholder sessions. As outlined in Section 5, engagement sessions will be accompanied by a newsletter to ensure subscribers remain informed on material IRP developments.

Enbridge Gas will continue to conduct Indigenous engagement through sharing ongoing IRP updates via the Enbridge Community and Indigenous Engagement newsletter as outlined in Section 5.

As Enbridge Gas continues the monitoring and review of the AMP, additional project specific engagement will be considered as applicable to the project scope. This includes engagement with municipalities, local LDCs and IESO to discuss demand forecasts and constraints in the area, as well as additional engagement with contract customers. Refinements to these processes will be considered with further experience.

Enhancements to the IRP webpage will continue, inclusive of updates to the IRP Pilot Project page, noted in Section 4.

Continued IRP Evaluation and Project Monitoring

Enbridge Gas will continue to conduct IRP screening and evaluation for projects within the capital plan.

An update on the projects reviewed from the AMP Addendum 2026 for the 2025-2034 period will be provided in the AMP Addendum 2027, anticipated to be filed in Fall 2026.

For projects that pass both the technical and economic evaluation, Enbridge Gas would develop and subsequently file a stand-alone non-Pilot IRP Plan application and supporting evidence with the OEB for approval where applicable.

Enbridge Gas will continue to work with Posterity Group as appropriate on updates to the IRP model through refreshing data inputs and refining modelling approaches, assumptions, and methodologies to improve forecasting of peak hourly flow reduction potential and costs. Additionally, Enbridge Gas will continue to refine the assumptions for ETEE and DR based on learnings and findings from the pilot as they become available.

DCF+ Test

Enbridge Gas will continue to consider feedback received in 2025 from the IRP TWG concerning the DCF+ enhancements and will file a submission on the DCF+ test as part of its first non-pilot IRP Plan application.[35]

Pilot Projects

As noted in Section 4, the OEB issued a Decision on the Southern Lake Huron IRP Pilot Project on March 27, 2025. In 2026, Enbridge Gas will continue to execute the SLH IRP Pilot plan included as Appendix H in the 2024 IRP Annual Report and updated as detailed in Section 4. The SLH IRP Pilot will continue to be updated, as necessary, as the IRP Pilot Project is implemented and evaluated. Enbridge Gas will continue to engage the IRP TWG for input and

[35] EB-2020-0091, IRP Planning Decision and Order, July 22, 2021, p. 56-57

review over the term of the pilot. The Pilot ETEE offers are expected to end by December 31, 2026, and the Pilot DR offer is expected to end by March 31, 2027. Pilot final reporting is expected in Q4 2027.

System Pruning

As noted in Section 10, Enbridge Gas has developed the approach for the pilot(s) in consultation with the TWG and initiated implementation of the pilot in 2025. Enbridge Gas will continue with field implementation of the pilot in 2026, inclusive of updating and consulting with the TWG on key elements as appropriate.

Policy Proposals

As per the Rebasing Phase 2 Settlement Proposal, Enbridge Gas agreed to propose an IRP incentive mechanism in its next IRP Plan application to the OEB, to be filed within one year of the date of filing of the Settlement Proposal (November 4, 2024). Enbridge Gas filed its IRP Incentive Mechanism application on November 4, 2025, where it also requested that the application be put into abeyance until the outcome of the IRP Framework Review proceeding is known. On December 22, 2025, the OEB granted the request, and the application currently remains in abeyance.

Framework Consultation

The OEB released a letter on March 27, 2025, outlining it was launching a consultation to support a review and evaluation of its IRP Framework for Enbridge Gas (EB-2025-0125). An OEB Staff report assessing progress implementing the IRP Framework and proposed updates to the IRP Framework was released in October 2025 and a stakeholder meeting was hosted on October 22, 2025, to discuss the proposed updates and solicit verbal comments. In response to the proposed updates, Enbridge Gas filed a written response to OEB staff's Discussion Paper on November 19, 2025. On April 28, 2026, the OEB issued a letter on the next steps for the IRP Framework, concluding its consultation and determining that Enbridge Gas should file an updated IRP Framework for adjudicative review by August 31,2026.

Appendix A: OEB IRP Directives and Progress Towards 2025 Priorities

The table below provides Enbridge Gas's progress toward meeting the Directives as ordered by the OEB in the IRP Decision. This is further described in detail in Rebasing Phase 3 (EB-2025-0064), Exhibit 1, Tab 13, Schedule 5.

Directive Item	Directive	Status
Interruptible rates	The OEB directs Enbridge Gas to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service.	Completed – filed with Enbridge Gas's 2024 Rebasing Application (EB-2022-0200, Exhibit 8, Tab 4, Schedule 7). As part of the approved Settlement Proposal, Enbridge Gas received approval to implement negotiated interruptible rates as part of an IRP plan (EB-2022-0200, Decision on Settlement Proposal, Schedule A, Page 50, Issue 28). Enbridge Gas filed the rate design for harmonized- franchise contract rate classes in EB-2025-0064, Phase 3 Exhibit 8, Tab 2, Schedule 2 for OEB approval. The proposed harmonized rate design for interruptible customers provides an increased price spread between firm and interruptible rates compared to the current rate design. The harmonized rate design also provides a predictable cost outcome for customers who choose to elect interruptible service by reducing the variance in the spread of firm and interruptible rates between rate classes and between individual rate classes in each rate class.
Documentation of demand-side IRPAs	The OEB concludes that a document on the best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report. The OEB agrees with Enbridge Gas that supply-side alternatives require case-by-case examination and therefore are not required to be included in the listing.	Completed – list included since 2022 IRP Annual Report. Updated list included in Appendix B - Integrated Resource Plan Alternatives.
Asset Management Plan	The OEB directs that the AMP include information about Enbridge Gas' system needs. This includes providing the status of consideration of IRP Plans regarding meeting system needs, the result of the binary screening, and details on the evaluation.	Completed – most recent version filed with the Enbridge Gas Ontario Asset Management Plan Addendum – 2026 (EB-2020-0091)

DCF+ test enhancement	The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP and, as applicable, file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.	In progress – will be filed as part of Enbridge Gas's first non-pilot IRP Plan application. The report Use of the Discounted Cash Flow-Plus Test in Integrated Resource Planning (IRP): Report of the IRP Technical Working Group presents the TWG's views on applying the DCF+ economic evaluation methodology.
IRP Website	The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholder engagement efforts.	Phase 1 – Completed Phase 2 – Completed See Section 5 for more details on stakeholder engagement.
Technical Working Group	Establishment of a TWG with the OEB directing that membership should include Enbridge Gas, OEB staff, independent experts, and experienced non-utility stakeholders	Completed. The TWG members were selected by OEB Staff as of December 6, 2021 with meetings commencing January 2022. The TWG membership, Terms of Reference and meeting folders with materials and minutes is available at Natural Gas Integrated Resource Planning (IRP) | Engage with Us (oeb.ca)
IRP Deferral accounts	The OEB directs Enbridge Gas to prepare a Draft Accounting Order for the two IRP Costs deferral accounts, consistent with the direction of this decision.	Completed. On August 12, 2021, Enbridge Gas filed its draft accounting orders for the IRP Operating Costs Deferral Account and IRP Capital Cost Deferral Account. From the OEB Settlement Decision for 2024 Rebasing Phase 1 (EB-2022-0200), parties agreed to the modifications made to the IRP Operating Costs Deferral Account and IRP Capital Cost Deferral Account.[36] From the OEB Settlement Decision for 2024 Rebasing Phase 2 (EB-2024-0111), parties agreed that a new IRP System Pruning Deferral Account with a $5 million cap will be created for recording

[36] EB-2022-0200, Exhibit O1, Tab 1, Schedule 2, September 12, 2023, p. 39 and 40,

		incremental costs related to these activities for later recovery.[37]
IRP Pilot projects	The OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022 as proposed by Enbridge Gas. The detailed consideration of IRP pilot projects should commence shortly after the issuance of the IRP Framework with input being sought from the IRP Technical Working Group described in Chapter 10 ("Stakeholder Outreach and Engagement Process").	In progress – See Section 4 for a summary on Pilot Project implementation which will continue as a multi-year priority. The requirement for Enbridge Gas to consult with the IRP TWG on a potential second IRP pilot is currently stayed by the OEB [38]

The table below provides Enbridge Gas's progress toward meeting the 2025 priorities as defined in the 2024 IRP Annual Report and 2024 IRP Technical Working Group report.

Priority	Activity	Status
External Stakeholder Outreach	External stakeholder outreach (including broader discussions with municipalities, regional engagement sessions, and geotargeted engagement in pilot areas)	Completed: • See Section 4 for a summary of the activities completed for the Southern Lake Huron Pilot Project and System Pruning Pilot Project. • See Section 5 for a summary of the activities completed for the stakeholder engagement process and Indigenous engagement.
Continued IRP Evaluations	IRP binary screening, and technical and economic evaluations of system needs in the AMP.	Completed: • See Section 3 for a summary of the IRP Assessment for investments in the AMP Addendum 2026. See Appendix C for a high-level breakdown of the investments screened or evaluated out of the AMP Addendum 2026 for IRP including the associated 2025-2034 forecast. • See Section 9 for a summary of the engagement on the results of economic evaluation and considerations to support alternative selection. See Appendix F, Economic Evaluation section, for a summary of the interpretation of DCF+ results. In-progress:

[37] EB-2024-0111, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p.19-20,
[38] Decision on Threshold Question and Procedural Order No. 2, EB-2025-0333, March 24, 2026, p.2.

Priority	Activity	Status
		• See Section 2 for a summary of refinements to the ETEE model. Posterity Group has incorporated the TWG input received in 2024, and the final report will be available in Q2 2026. Learnings and findings from the SLH Pilot Project will be considered as they become available. • See Section 9 for a summary of the consultation on learnings from the economic evaluation results. These results will inform the IRP Framework review proceeding in 2026.
DCF+ Test	DCF+ Test consultation and methodology	Completed – See Section 9 for a summary of the consultation conducted. The positions of parties are well understood, and Enbridge Gas intends to bring forward its application of the DCF+ methodology with its first non-pilot IRP Plan.
IRP Pilot Project	Pilot project execution	In progress – See Section 4 for a summary on IRP Pilot Project implementation which will continue as a multi-year priority.
System Pruning	Develop its approach to system pruning in consultation with the IRP TWG by end of Q2 2025 and begin implementation of one or two pilots by end of Q1 2026.	In progress – See Section 4 for a summary of system pruning pilot project implementation which will continue as a multi-year priority.
Policy Proposals (for non-pilot IRP Plans)	Role of shareholder Incentives/ performance metrics for IRP, incrementality and use of IRP deferral accounts, treatment of risk, attribution between DSM and IRP.	Complete – IRP Incentive Mechanism application was filed on November 4, 2025 – the application currently remains in abeyance. In progress – the focus of the 2025 consultation prioritized the IRP Incentive Mechanism as opposed to a continuation of consultation on the additional IRP-related policy proposals. In relation to a broader IRP jurisdictional scan, the jurisdictional scan conducted by DNV for system pruning also included information related to non-pipe alternative programs and policies due to the infancy of system pruning activities. The approach for the policy proposals and additional jurisdictional review will be considered alongside the next steps in the IRP Framework Review proceeding.

Priority	Activity	Status
Framework Consultation	Engage in the Framework Review discussions led by OEB Staff during TWG meetings and participate in the Framework Review consultation	Completed – OEB staff engaged the TWG over the course of 2025. Enbridge Gas was a participant in the OEB consultation. The OEB issued a letter in April 2026 on the next steps for the IRP Framework, and has determined that Enbridge Gas should file an updated IRP Framework for adjudicative review by August 31,2026.

Appendix B: Integrated Resource Planning Alternatives

As per the IRP Decision, the IRP Annual Report is to include "a summary of the best available information on demand-side IRPAs, including the types of IRPAs, estimates of cost, peak demand savings, status in Ontario and learnings from pilot projects and other jurisdictions". Additionally, a summary of the best available information on supply-side IRPAs has been included below.

Demand Side IRP Alternatives

Enhanced Targeted Energy Efficiency ("ETEE")

IRPA Overview
Enhanced targeted energy efficiency ("ETEE") programs focus on achieving necessary reductions in a specific geographical area to reduce peak period system demands. ETEE programs could include enhancing existing broad-based Demand Side Management ("DSM") offerings through additional incentives and targeted marketing, or introducing new geo-targeted programs not offered through broad-based DSM. The mix of offerings and measures utilized in an ETEE program is dependent on the scope of the facility investment project under consideration, customer characteristics in the specific project services area, past DSM participation, etc. Broad-based DSM programs have been offered to natural gas customers across Ontario since 1993. On November 15, 2022, the OEB issued its Decision for the Company's 2023-2025 DSM Plan (EB-2021-0002) to guide ongoing broad-based DSM programming. As defined by the OEB in their DSM Letter, the objective of broad-based DSM is "assisting customers in making their homes and businesses more efficient in order to help better manage their energy bills". As ETEE programs focus on peak hour reductions, many ETEE measures would focus on enhancing existing broad-based DSM measures such as space heating equipment and building envelope upgrades. Enbridge Gas is undertaking the IRP Pilot Project (EB-2022-0335) to develop an understanding of how to design, deploy and evaluate ETEE programs and how ETEE programs impact peak hour demand within a geo-targeted area. The learnings from these IRP Pilots, as well as any non-pilot IRP Plans, will be incorporated into future iterations of the IRP Annual Report's Appendix B, "Demand Side Alternatives".
IRPA Peak Impacts
Forecast peak impacts will be estimated on a case-by-case basis depending on the ETEE program. Enbridge Gas worked with Posterity Group to build an end-use model of its service territory with the 2019 Achievable Potential Study ("APS") being the starting point for the IRP model. First, a mirror model of the APS was created and then several adjustments were made to better reflect Enbridge Gas's knowledge and experience of the Ontario DSM market, Enbridge Gas's current Technical Resource Manual (TRM) assumptions, and known changes to applicable standards.[39] Posterity Group then worked with Enbridge Gas to develop peak factors which were added to the IRP model so that enhanced targeted energy efficiency peak hour impact estimates could be developed for each region, sector, segment, and end use.[40] Posterity Group's IRP model is run through Posterity's

[39] Posterity Group report detailing the development and assumptions of the underlying mirror model (EB-2021-002, Exhibit E, Tab 4, Schedule 7, Attachment 1 – "Demand Side Management Planning Support Final Report Documenting Data Inputs, Assumptions and Method (April 2021)" - Link

[40] Posterity Group memo on peak modelling methodology and hours-use peak factor assumptions (filed as part of EB-2022-0157 (PREP) – Exhibit I.ED.7, Attachment 4) - Link. Posterity Group memo on calculation of peak reduction on an efficiency measure (July 2022) - Link

Navigator software, where the details in how the Navigator software works and how the model parameters interact with each other are available and documented.[41] Posterity Group and Enbridge Gas work to evolve this model by refining assumptions and assessment methodologies to refine and improve forecasting of peak hourly flow reduction potential. It is expected that the ETEE programs as part of the IRP Pilots will provide greater insight on the peak impacts of such programs.
IRPA Cost Details
Costs will be determined on a case-by-case basis depending on the ETEE program. The Posterity model described above also includes cost assumptions for ETEE programs, based largely on the APS, with adjustments made in an attempt to better reflect Enbridge Gas' knowledge and experience of the Ontario DSM market.[42] Posterity Group and Enbridge Gas evolve this model as required by refining assumptions and assessment methodologies so it can be used to assess project specific costs for an ETEE program. It is expected that the ETEE programs as part of the IRP Pilots will provide greater insight on the costs of such programs.
IRPA Deployment Strategy
The selection of energy efficiency measures for an ETEE program and the deployment strategy would be dependent upon the scope of the facility investment project under consideration, customer characteristics in the specific project service area, past DSM participation, etc. The IRP Pilots will provide insights that could guide the deployment strategy of future IRP ETEE programs. The pilots could also provide insights on the deployment strategy into the richness of customer ETEE incentive levels and the intensity of the ETEE program delivery approaches for various customer groups to drive the participation uptake levels necessary to meet peak demand reduction requirements.
IRPA Solution Timing
Timing on an ETEE IRPA solution is dependent upon the scope of the facility system need under consideration, the type of ETEE program(s) being considered, and the customer characteristics in the specific project service area. A high-level estimate of a 3-to-5-year minimum lead time would be required to support program implementation and deployment, and subsequent performance measurement to evaluate the impact to the system peak hour. ETEE can be deployed with supply-side IRPA(s) to defer the system need and ensure that Enbridge Gas can reliably meet peak hour system demand requirements while demand-side ETEE IRPA(s) are implemented.
IRPA Implementation Risks/Challenges
There are several operational risks related to ETEE: - Principle of universality (offering different DSM programing and incentives to different customers). - Undersubscription of ETEE programming to meet peak demand requirements to delay or avoid the facility system need. - Uncertainty on the reliability of peak reduction capabilities of ETEE measures to be delivered in a cost-effective manner for facility planning. - Coordination of timing between fully effective ETEE IRPAs and meeting the system needs.

[41] Posterity Group, Enbridge's Navigator End-Use Model Presentation: Posterity (Enbridge's Navigator End-Use Model) and "Navigator Energy and Emissions Simulation Suite – Functional Specification Document" (filed in EB-2022-0200 – Exhibit I.1.10-SEC-29, Attachment 1) - Link

[42] Posterity Group report detailing changes to reference case assumptions on DSM measures (EB-2021-002, Exhibit E, Tab 4, Schedule 7, Attachment 1, Appendix A) – "Demand Side Management Planning Support Final Report Documenting Data Inputs, Assumptions and Method (April 2021)" - Link

- Current lack of experience in implementing ETEE programming; DSM expertise in delivery programming has been broad-based.
- Variances in energy planning and the lack of coordinated energy planning between gas utilities, electric distributors and the IESO. Risk of insufficient electrical capacity to absorb electric measures as part of an ETEE program.

Learnings from Pilot Projects/Other Jurisdictions

Enbridge Gas filed a Geo-Target Demand Side Management Case Study in EB-2020-0091 at Exhibit C, Appendix A. The objectives of the case study were:

1. Assessment of the impacts of geo-targeted DSM programs on reducing peak hour demand.
2. Assessment of the costs of geo-targeted DSM program implementation.

The results from this case study only illustrate the impacts geo-targeted DSM had on the town of Ingleside and although informative and directional, the results cannot be generally applied due to the specific nature of customer composition.

In 2022, Enbridge Gas engaged Guidehouse to undertake a jurisdictional review of ETEE and DR natural gas pilots implemented for general service customers, where the pilots' objectives were to defer or avoid infrastructure.[43] Guidehouse focused on three jurisdictions, summarizing the pilot objectives, marketing activities, costs, findings, and challenges faced. Additionally, Guidehouse noted challenges in data availability in completing the jurisdictional review.

As part of the first-generation IRP Framework, the OEB determined that it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs. However, a limited number of electrification measures are included in the Southern Lake Huron pilot project and System Pruning pilot.

In 2023, Enbridge Gas undertook some jurisdictional research in-house to better understand how non-pipeline electric alternatives could be offered more broadly in the future, including attending industry webinars.44 High-level learnings include that the Colorado Public Utilities Commission includes beneficial electrification as a non-pipeline alternative to offset gas infrastructure investments in the long-term.[45] [46] The New York Public Commission encourages gas utilities in New York to offer building electrification as a non-pipeline alternative as part of a program to remove leaking or leak-prone gas infrastructure. In California, the California Public Utilities Commission considers electrification as a non-pipeline alternative to meet energy needs in utilities gas-planning activities, and one utility is offering a small electrification program to facilitate the retirement of gas assets.47 Additionally, the California Energy Commission is funding two building electrification and gas infrastructure decommissioning pilots.[48] Many of the utilities reviewed in other jurisdictions are dual-fuel utilities with ability to coordinate internally, whereas Enbridge Gas would require coordinated planning with the IESO and LDCs to consider similar electrification plans. Enbridge Gas intends to continue its jurisdictional research into non-pipeline electric alternatives as part of its IRP demand-side alternatives, and of jurisdictions seeking to electrify customers as a means to decommission natural gas distribution pipelines.

In 2025, DNV was engaged to conduct a jurisdictional scan to support the development of the System Pruning pilot approach.[49] The purpose of this study was to better understand and gain insights into how gas utilities among

[43] IRP ETEE-DR Pilot Review April 8, 2022 Guidehouse (IRP ETEE-DR Pilot Review)
[44] TWG Meeting #32 (December 12, 2023) (link)
[45] Strategen, Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado, October 2023. (link)
[46] Berkley Lab, Not Just a Pipe Dream: Non-Pipeline Alternative Framework Analysis and Experiences. (link and recording)
[47] Strategen, Non-Pipeline Alternatives to Natural Gas Utility Infrastructure: An Examination of Existing Regulatory Approaches, November 2023. (link)
[48] California Energy Commission, Gas Research and Development Program Proposed Budget Plan for Fiscal Year 2023-2024, May 2023. CEC-500-2023-020.pdf (ca.gov)
[49] Engage with us, OEB (link)

North American and European jurisdictions are approaching pruning to their gas distribution pipelines, where informative to the Ontario context. The scan covered six utilities/jurisdictions – five were selected as they have planned or undertaken system pruning or non-pipeline activities, and one was selected because of their successful collaboration activities amongst the gas and electric utilities within that jurisdiction. Of the six studied jurisdictions, only two (California and New York) have completed actual system pruning projects. The study found that system pruning is a utility action in its infancy. Among the reviewed jurisdictions, the primary driver of system pruning or non-pipeline alternative activities is a policy framework centered around climate and equity. Although considerations about system cost represent a concern, it was not explicitly cited as the driver to policies that promote system pruning and NPAs.

Demand Response ("DR")

IRPA Overview
Natural gas demand response aims to reduce natural gas customers' demand during peak periods. For residential and commercial customers, this can commonly be seen in the form of gas demand reductions during DR program events via thermostat control or water heater temperature settings. For contract customers, this can be done through leveraging interruptible rates. Demand response would include: 1. Negotiable interruptible rate - as detailed in Section 9, the use of interruptible rates was reviewed as part of the IRP Framework Decision, and Enbridge Gas filed an Interruptible Rate Study that evaluated the use of demand response in the context of future IRP Plan Application where applicable. 2. Utilization of another alternative (i.e., onsite CNG) when a peak hour/day event is called. 3. Incentives to shift peak hourly demands to off-peak periods. Enbridge Gas is undertaking the IRP Pilot Project (EB-2022-0335) to develop an understanding of how to design, deploy and evaluate residential DR programs and how residential DR programs impacts peak hour demand within a geo-targeted area. The learnings from the IRP Pilot, as well as any non-pilot IRP Plans, will be incorporated into future iterations of the IRP Annual Report's Appendix B, "Demand Side Alternatives".
IRPA Peak Impacts
Peak impacts will be determined on a case-by-case basis depending on the DR service (e.g., program, rate design etc.). As a starting point for a residential space heating smart thermostat program, an estimated impact of 18.5% peak gas (m3/hr) reduction was developed based on the evaluation of SoCal's residential smart thermostat DR program[50] and adjusted for Ontario climate/buildings.[51] It is expected that the residential DR program as part of the IRP Pilot Projects will provide greater insight on the peak impacts of such a program.
IRPA Cost Details
DR IRPA costs will be determined on a case-by-case basis depending on the DR service (e.g., program, rate design etc.). It is expected that the residential DR program as part of the IRP Pilot Projects will provide greater insight on the actual costs to deploy such a program.

[50] https://www.calmac.org/publications/SoCalGas_2019_DR_Evaluation_Report_-_PUBLIC_FINAL.pdf
[51] Adjustment for Ontario climate/buildings provided on p.2 - Link

IRPA Deployment Strategy
The deployment strategy will be determined on a case-by-case basis depending on the customer mix and characteristics in the project area. The IRP Pilot residential DR program will provide insights that could guide the deployment strategy for future programming. For contract rate customers, as part of the IRP evaluation process, Enbridge Gas engages with all contract customers in the project area to assess whether those customers could reduce their peak demands, convert their firm demand service to interruptible service or leverage another fuel source.
IRPA Solution Timing
DR IRPAs are dependent upon the scope of the facility system need under consideration, the type of DR program being considered, and the customer characteristics in the specific project service area. The IRP Pilot residential DR program will provide insight on the time required to design a DR program and to deliver a DR program to reach participation levels required to inform future assessment for specific facility IRPAs. Engagement of contract rate customers will occur as part of the detailed technical assessment.
IRPA Implementation Risks/Challenges
There are several operational risks related to a residential DR program: • Principle of universality (offering DR programing/incentives to different geographically specific customers) • Undersubscription and lack of persistent participation of DR programming to meet peak demand requirements of the delay or avoidance of facility system need • Uncertainty on the reliability of cost-effective DR performance for facility planning • Coordination of timing between fully effective DR IRPAs and meeting the system needs • Current lack of experience in implementing DR programming; Enbridge Gas has not previously implemented a gas-DR program for general service customers.
Learnings from Pilot Projects/Other Jurisdictions
In 2022, Enbridge Gas engaged Guidehouse to undertake a jurisdictional review of ETEE and DR gas pilots implemented for general service customers, where the pilots' objectives were to defer or avoid infrastructure [52]. Guidehouse focused on three jurisdictions, summarizing the pilot objectives, marketing activities, costs, findings, and challenges faced. Additionally, Guidehouse noted challenges in data availability in completing the jurisdictional review.

[52] IRP ETEE-DR Pilot Review April 8, 2022 Guidehouse (IRP ETEE-DR Pilot Review)

Supply Side IRP Alternatives

Compressed Natural Gas ("CNG")

IRPA Overview
CNG is a mobile solution that can be used in place of traditional pipeline reinforcement to meet customer demands at peak hours on peak days. Natural gas is compressed into large tube trailers and moved by trucks from the compression station "hub" to a mobile decompression station "spoke" where the gas is delivered into the pipeline. This is an active control best utilized in long, single feed pipe networks with cold weather peaking loads. Hub stations are situated in relative proximity to spoke stations (within 200 kms) to minimize driving distance.
IRPA Peak Impacts
CNG targets peak hours on peak demand days, where the injection of gas back into the system at the spoke station would have an equivalent 1 for 1 offset of gas otherwise required to flow through the traditional pipeline bottleneck. Injecting near the low-pressure point on the system would magnify the benefit beyond 1 for 1 on a hydraulic basis. Although the trailered gas will need to be withdrawn from the system at the hub station, this can be done at off-peak times and locations and where capacity is available.
IRPA Cost Details
From a capital cost perspective: • Tube trailers typically have a capacity of 10,000 m^3 of natural gas (at standard conditions) and cost approximately $700,000 per trailer with a 15-year useful life. • Hub and spoke stations costs can vary based on capacity requirements, but typically cost approximately $300,000 and $3M per station, respectively, with a 20+ year useful life. Capital costs may be impacted by the procurement strategy of utilizing a third-party vendor or procurement of the asset by Enbridge Gas. From an operational cost perspective, the equipment requires regular maintenance and supervised operation. Drivers are also required to drive the trailers between the hub and spoke stations with highway tractors.
IRPA Deployment Strategy & Timing
The equipment is mobile and can be deployed in various locations throughout the province. CNG would be most ideal in areas where the gas demands are large enough to achieve economies of scale but small enough to be practical. For instance, the transmission pipeline scale is too large as it may require hundreds of trailers, but a few households would be too small as a single trailer will be underutilized. Additional consideration based on location would impact the suitability of CNG as a solution, such as urban versus rural and the number of trucks required. Depending on the system need and location, CNG can be a suitable bridging solution for ETEE implementation or for the deferral of baseline facility projects as system needs may evolve, inclusive of the energy transition landscape in Ontario. CNG can be deployed in a relatively short amount of time, and can be scalable by the addition of mobile compressor stations and trailers.
IRPA Implementation Risks/Challenges
The biggest risk associated with this solution is a potential disruption in the supply of trailers to the spoke station, for instance road closure due to weather or an accident while in transit. To mitigate this risk, extra trailers can be made available on-site at the spoke station and the associated additional costs would need to be considered when assessing the viability of this IRPA.

Market-Based Supply

IRPA Overview

Market-based supply-side IRP alternatives include incremental natural gas deliveries or pressure increases at specific interconnects between Enbridge Gas's system and other pipelines, such as the TC Energy Mainline and US based pipelines including Panhandle Eastern Pipeline Company and Vector. These alternatives are considered in the IRP assessment as governed by the IRP framework and are incremental to the options previously considered as part of gas supply planning, as governed by the Gas Supply Framework.

Contracting for market-based supply-side alternatives into Enbridge Gas's franchise area, where applicable and available, can reduce, defer or mitigate traditional infrastructure by meeting incremental natural gas demands in a defined area through incremental deliveries or increased pressures.

IRPA Peak Impacts

Incremental deliveries or increased pressure must be delivered in the project area to impact peak hour demands. Therefore, market-based supply side alternative options are limited to interconnects with TC Energy along the mainline and Enbridge Gas's system or with interconnects with other pipelines that connect to Enbridge Gas's system such as Parkway, Ojibway and Dawn.

IRPA Cost Details

Market-based supply-side alternative costs are based on market dynamics at the time of contracting. Enbridge Gas cannot forecast the cost of market-based supply-side options on a long-term basis. The IRPA costs will be incremental to options previously considered under gas supply planning, as governed by the Gas Supply Framework.

IRPA Deployment Strategy and Timing

Enbridge Gas can contract and deploy market-based supply-side alternatives if the deliveries from a third party or pipeline are available.

While U.S. interstate pipelines regulated by the Federal Energy Regulatory Commission are permitted to offer both short-term and long-term transportation services, access to incremental capacity at specific interconnects is subject to upstream capacity availability, tariff terms, and commercial negotiations. In practice, opportunities to secure market-based supply-side services from U.S. pipelines are market condition dependent, and may be limited in duration, and location. As many of Enbridge Gas's interconnects are with U.S. pipelines, these factors must be assessed on a case by case scenario to determine the extent to which market-based supply-side services can be relied upon as IRP alternatives.

IRPA Implementation Risks/Challenges

There are two primary operational risks with market-based supply-side alternatives: limited availability of incremental capacity and delivery risk.

Market-based supply side alternatives rely on availability of incremental capacity at specific interconnects, which is contingent upon upstream pipeline conditions and competing market demand, particularly during peak periods. As a result, while market-based supply-side alternatives may be used to defer a facility project in the near term where capacity is available, their ability to fully mitigate a need over the planning horizon is uncertain. In instances, a market-based supply-side alternative could be used to defer a project in the short-term and then the need and IRP alternatives will need to be reassessed.

While Enbridge Gas may have contracted for a market-based supply side alternative, if the capacity underpinning the service is not firm, then natural gas market dynamics may cause the supplier to fail on its delivery obligations. For example, without firm capacity underpinning the market-based service, during peak weather events upstream pipeline systems may become constrained and non-firm services can be curtailed. If the service provider is relying on non-firm services, it may be unable to supply natural gas to Enbridge Gas. While contract penalties and other contract language may limit most events like the example above from happening, it remains a legitimate and

material risk. If the contracted service was not delivered as planned, Enbridge Gas could have insufficient gas supply deliveries to meet its market demands; potentially resulting in a system outage during the coldest periods of the year. While Enbridge Gas would collect financial penalties, if applicable, after the event occurred, Enbridge Gas would still need to deal with the physical and customer impacts that resulted due to the failed delivery of the incremental gas on that day.

Appendix C: IRP Screening and Evaluation Results

This section includes the following summaries on the IRP screening and evaluation results:

- Investments that did not pass the initial screening stage are included in Table 1
- Investments that did not pass the binary screening stage are included in Table 2
- Investments that did not pass the technical screening stage are included in Table 3 [53]
- Investments that did not pass the technical evaluation stage are included in Table 4
- Investments that did not pass the economic evaluation stage are included in Table 5

Table 1 – Breakdown of Investments Screened out in Initial Screening of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Non-Gas Carrying	$1,048M	334
Grand Total	**$1,048 M**	**334**

Table 2 – Breakdown of Investments Screened out in Binary Screening of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Customer Connection – related projects are required to serve new customers connected in accordance with guidelines of EBO 188. The OEB concluded that as part of the first-generation IRP Framework it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs.	$1,231.7 M	112
Customer Specific Build - If an identified system constraint/need has been underpinned by a specific customer's (or group of customers') clear request for a facility option and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then it is not appropriate to conduct IRP analysis for those projects.	$127.1 M	8
Dollar Threshold - If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then an IRP evaluation is not required.	$455.1 M	634
Economic Development - If a facility project has been driven by government legislation or policy with related funding explicitly	$7.8 M	2

[53] Appendix F, Table 1 outlines investment categories screened out for IRP at the technical screening stage and the associated rationale.

aimed at delivering natural gas into communities, then an IRP evaluation is not required		
Emergent Safety - If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required.	$13.8 M	6
Timing – If an identified system constraint/need must be met in under 3 years, an IRPA cannot be implemented and its ability to resolve the identified system constraint/need cannot be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.	$0.01 M[54]	1
Grand Total	**$1,835.5 M**	**763**

Table 3 – Breakdown of Investments Technically Screened out of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
NPS 2, cannot downsize or retire	$16.3 M	6
Compression Station related projects are required to maintain existing deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions.	$453.4 M	628
Storage Pools & Well related projects are required to maintain existing deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions.	$108.6 M	88
Hydrogen related projects are required as no IRPAs can replace the hydrogen feasibility assessments and hydrogen blending initiatives.	$7.96 M	1
Distribution station condition related, IRPA not applicable	$365.8 M	544
Additional Screening for Investment descriptions where IRPAs are not applicable[53]	$2,255.4 M	324
Project Status/Timing Related	$251.4 M	19
Grand Total	**$3,458.9 M**	**1610**

The category in Table 3 with the highest capital costs is “Additional Screening for Investment descriptions where IRPAs are not applicable” [53].

[54] Investment #103275 (ISD 2022, Growth asset class) was binary screened out for “Timing” in the 2023-2032 Asset Management Plan. The $0.01 M amount pertains to final project closeout costs.

Table 4 – Breakdown of Investments Technically Evaluated out of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Potential project scope could be replaced with NPS 2. IRPAs not applicable and scope to be confirmed when project enters the detailed design phase.	$152.2 M	55
IRPAs unable to defer, reduce or eliminate project scope.	$2.9 M	1
Grand Total	**$155.1 M**	**56**

Table 5 – Breakdown of Investments Economically Evaluated out of the 2025-2034 AMP for IRP

Category	2025-2034 Forecast (Includes overhead allocation)	# of Investments
Facility alternative is the optimal solution, and the project scope will be monitored. Annual review of the facility and IRP alternatives will be conducted to confirm optimal solution prior to alternative implementation.[55]	$30.1 M	20
Pilot Project	$0.3 M	1
Grand Total	**$30.4 M**	**21**

[55] The facility was the optimal solution at both the Ph1 and Ph1+2 level for the investments evaluated.
For the subset of investments applicable to supply-side alternatives, a cost reduction in the range of 85% to 150% would be required for the supply-side alternative to achieve parity with the facility alternative at Ph 1 and Ph 1+2. This outcome is driven by the need to construct a facility once the supply-side deferral period ends.

For the subset of investments applicable to demand-side alternatives, a cost reduction in the range of 100% to 150% was required for the demand-side alternative to achieve parity with the facility alternative at Ph 1 and a cost reduction in the range of 50% to 150% at Ph1+2. This outcome is driven by relatively higher demand-side implementation costs compared to the achievable cost savings.

Appendix D: IRP Screening Results for Facility Applications

This section provides a summary of any on-going facility applications or facility applications where an OEB Decision was provided in 2025.This section does not include LTC Exemption Applications.[56]

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
EB-2023-0343	East Gwillimbury Community Expansion Project			Fail	Enbridge Gas has applied the Binary Screening Criteria and determined this Project meets the definition of a community expansion project, as defined in the IRP Framework, as the Project has been approved by the government of Ontario as part of the Phase 2 NGEP, to provide access to natural gas services in the Town of East Gwillimbury. The IRP Framework Decision explains that "Given the goal of the Ontario Government's Access to Natural Gas legislation to extend gas service to designated communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need.	Proceeding is currently in progress.
EB-2024-0187	Boblo Community Expansion Project			Fail	Enbridge Gas has applied the Binary Screening Criteria and determined this Project meets the definition of a community expansion project, as defined in the IRP Framework, as the Project has been approved by the government of Ontario as part of the Phase 2 NGEP, to provide access to natural gas services in the Town of East Gwillimbury. The IRP Framework Decision explains that "Given the goal of the Ontario Government's Access to Natural Gas legislation to extend gas service to designated	Proceeding is currently in progress.

[56] On September 24,2024, the OEB released new Filing Requirements applicable for exemption on hydrocarbon line projects that cost between $2M and $10M, where information on project need and alternatives are not required.

Filed: 2026-07-30, EB-2026-0108, Exhibit G, Tab 2, Schedule 1, Page 53 of 141

OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need.	
EB-2024-0200	St. Laurent Pipeline Replacement Project				As this is a pipeline integrity project, the IRP Analysis for this project was limited to whether the proposed pipeline size can be reduced, as neither a supply side or demand side alternative would adequately address the corrosion and third party damage risk. Enbridge Gas reviewed potential IRPA such as incremental gas supply, trucked CNG, ETEE and for contract customers to de-contract or convert existing firm service to an interruptible service. These alternatives were found to not be technically feasible or viable solutions.	OEB Decision dated March 18, 2025: The OEB grants Enbridge Gas's application for leave to construct the project. The OEB finds that the Project is in the public interest based on an examination of the Project need, alternatives, cost and economics, environmental impacts, land use requirements, and Indigenous consultation. The OEB finds that Enbridge Gas's consideration of alternatives, which included facility and non-facility alternatives, is sufficient to demonstrate that full replacement is the preferred option in this case.
EB-2024-0304	2025 Waubuno Well Drilling Project				Enbridge Gas has applied the Technical Screening Criteria and determined that the Project Need does not warrant further IRP consideration as this project is driven by the need to maintain deliverability and throughput.	On May 8, 2025, the OEB issued a report to the Minister of Natural Resources recommending the issuance of a well drilling license to Enbridge Gas for the well, subject to certain Conditions of License.
EB-2024-0322	Kimball-Colinville and Bickford MOP Increase Project				Enbridge Gas is undertaking this project to increase the storage capacity of the Kimball-Colinville and Bickford Storage Pools. Since the underground storage reefs are finite containers with defined boundaries, the only way to physically increase the storage capacity of the reefs is to increase the MOP, allowing more gas to be stored in the reef. Enbridge Gas stated that it is	OEB Decision dated May 13, 2025: The OEB grants Enbridge Gas approval to increase the MOP of the Kimball-Colinville and Bickford Storage Pools subject to certain conditions. The OEB accepts Enbridge Gas's assessment that there are no alternatives to increase the

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OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					not aware of any alternative to increase the capacity (volume) in the reef.	storage capacity of the Storage Pools other than through an increase in the MOP.
EB-2025-0073	Mississauga Reinforcement Project	Fail			Enbridge Gas has applied the Binary Screening Criteria and determined that this Project meets the definition of a Customer-Specific Build, as defined in the IRP framework, Customer-Specific Builds Customer-Specific Builds – if an identified system need has been underpinned by a specific customer's (or group of customers) clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.	OEB Decision dated February 19, 2026: The OEB grants Enbridge Gas's application for the leave to construct the project. The OEB finds that the Project is in the public interest based on an examination of the Project need, alternatives, cost and economics, environmental impacts, land use requirements, and Indigenous consultation. The OEB finds that Enbridge Gas's consideration of alternatives, which included facility and non-facility alternatives, is sufficient to demonstrate that full replacement is the preferred option in this case.
EB-2025-0271	Washago Community Expansion Project			Fail	Enbridge Gas has applied the Binary Screening Criteria and determined this Project meets the definition of a community expansion project, as defined in the IRP Framework, as the Project has been approved by the government of Ontario as part of the Phase 2 NGEP, to provide access to natural gas services in the community of Washago and surrounding areas. The IRP Framework Decision explains that "Given the goal of the Ontario Government's Access to Natural Gas legislation to extend gas service to designated communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need.	Proceeding is currently in progress.

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OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
EB-2025-0301	Port Colborne Reinforcement Project	Fail			Enbridge Gas applied the IRP Binary Screening Criteria and determined that this Project meets the definition of a Customer-Specific Build, as defined in the IRP Framework: Customer-Specific Builds – If an identified system need has been underpinned by a specific customer's (or group of customers') clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.	Proceeding is currently in progress.
EB-2025-0306	Lanark and Balderson Community Expansion Project			Fail	Enbridge Gas has applied the Binary Screening Criteria and determined that because the Project is a community expansion project driven by government legislation, an IRP evaluation is not required. In its Decision and Order on the IRP Framework, the OEB explains that "[g]iven the goal of the Ontario Government's Access to Natural Gas legislation to extend gas service to designated communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need.	Proceeding is currently in progress.
EB-2025-0307	Waubuno Gathering System and Compressor Replacement Project				Enbridge Gas has applied the Technical Screening criteria and determined that the Project Need, does not warrant further IRP consideration. This project is required to maintain existing physical storage space capacity and capability.	Proceeding is currently in progress.
EB-2025-0293	2026 Kimball-Colinville Well Drilling Project				Enbridge Gas has applied the Technical Screening criteria and determined that the Project need does not warrant further IRP consideration as the Project is driven by the need to maintain existing injection and withdrawal capability and system	Proceeding is currently in progress.

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OEB Proceeding Docket	Project Name	Binary Screening Results			Enbridge Gas IRP Analysis	OEB Regulatory Proceeding Status
		Customer Specific Build	Timing	Community Expansion & Economic Development		
					throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions.	

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Appendix E: Technical Working Group Report

Review of Enbridge Gas Inc. 2025 Integrated Resource Planning (IRP) Annual Report and Update on IRP Working Group Activities

From: Integrated Resource Planning Technical Working Group

May 29, 2026

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1. Introduction and Overview of IRP Working Group

The Ontario Energy Board (OEB) established a first-generation Integrated Resource Planning (IRP) Framework for Enbridge Gas through its July 22, 2021 Decision and Order (IRP Decision). The IRP Decision directed the OEB to establish an IRP Technical Working Group (Working Group) and required that a Working Group report be filed in the same proceeding as Enbridge Gas's annual IRP report. The Working Group was formed and announced in a letter issued by the OEB on December 6, 2021, and has been active since then.

This Working Group report provides:

- The Working Group's review of Enbridge Gas's Annual IRP Report and comments on Enbridge Gas's implementation of the IRP Framework in 2025 and priorities for 2026, including individual member comments or concerns. (**Chapter 2**)
- A summary of activities undertaken by the Working Group from mid-June 2025 to the end of 2025. Activities prior to this are covered in the previous Working Group report.[1] (**Chapter 3**)

The Working Group report was prepared by OEB staff with input from all current Working Group members and approved by them as an accurate summary of the Working Group's activities.[2] This report clearly indicates where opinions expressed in the report do not reflect the views of all members.

1.1. Overview and Membership of IRP Working Group

The Working Group was established with an objective to provide input on IRP issues that will be of value to both Enbridge Gas in implementing IRP and to the OEB in its oversight of the IRP Framework. Members of the Working Group were determined through a call for nomination process where the OEB selected non-utility members, representatives from the OEB and Enbridge Gas, and an observer from the Independent Electricity System Operator (IESO). Other Enbridge Gas representatives also attend Working Group meetings as required, depending on the topics under discussion. For example, Catherine McCowan leads the system pruning work

[1] Previous Working Group reports have included details of Working Group activities beyond the end of the calendar year until near the date of report issuance. In order to align with the time period covered by Enbridge Gas's annual IRP report, this year's Working Group report only includes activities up to the end of 2025 (and thus covers a shorter time period than previous reports).
[2] The Working Group includes an observer from the Independent Electricity System Operator. As noted in the Working Group's Terms of Reference, any materials authored by the IRP Working Group (including this report) should not be considered to represent the views of Working Group observers or their organizations.

for Enbridge Gas and Eric Buan leads the work on the Southern Lake Huron Pilot and attended Working Group meetings in these capacities in 2025.

There were no Working Group member changes over the past year:

Table 1: Current IRP Working Group Membership

Name	Role
Michael Parkes	OEB staff representative (Working Group chair)
Stephanie Cheng	OEB staff representative
Alison Moore	Enbridge Gas representative
Whitney Wong	Enbridge Gas representative
Helen Tong	Enbridge Gas representative
John Dikeos, ICF Consulting Canada Inc.	Non-utility member
Tamara Kuiken, DNV Inc.	Non-utility member
Cameron Leitch, Enwave Energy Corporation	Non-utility member
Chris Neme, Energy Futures Group	Non-utility member
Dwayne Quinn, DR Quinn & Associates Ltd.	Non-utility member
Jay Shepherd, Shepherd Rubenstein Professional Corporation	Non-utility member
Stuti Rungee, Independent Electricity System Operator	Observer

Meeting notes and materials for all IRP Working Group meetings are published on the OEB's website following meetings to document key discussion points and to allow stakeholders to follow the Working Group's progress.[3] These materials can be found at: https://engagewithus.oeb.ca/irp

[3] Meeting materials are typically posted online shortly after the meeting. Meeting notes are not typically posted until after the following meeting, to allow for members to review draft notes and identify any omissions or inaccuracies.

2. Review of Enbridge Gas's Annual IRP Report and Comments on IRP Framework Implementation

Per the IRP Decision, the Working Group is expected to review a draft of Enbridge Gas's annual IRP report. The review is coordinated by OEB staff.

Enbridge Gas is expected to provide the Working Group with a draft of its annual IRP report far enough in advance of its planned filing with the OEB to allow the Working Group adequate time to review and comment. The IRP Decision also stipulates that the Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Working Group.

Consistent with prior years, the Working Group's review took the following steps:

STEP 1:

Enbridge Gas

Provided a draft of its 2025 IRP annual report to the Working Group for review.

STEP 2:

Working Group Members

Provided suggested edits/ comments/ clarifying questions.

STEP 3:

Enbridge Gas

Revised and finalized its annual report.

- Enbridge Gas discussed member comments at the April 8, 2026 meeting.
- Enbridge Gas subsequently finalized its annual report, documenting how it addressed comments from Working Group members. Final determinations as to the contents of Enbridge Gas's IRP annual report were made by Enbridge Gas, not the Working Group.



STEP 4:

Working Group Members

Provided final individual comments on implementation of the IRP Framework for inclusion in the Working Group report.

Member comments are discussed further below in Section 2.1.

2.1. Working Group Comments on the Implementation of the IRP Framework and 2026 IRP Priorities

Working Group members reviewed Enbridge Gas's description of its IRP activities in its 2025 IRP annual report (sections 1-9 of the annual report, plus relevant appendices) and also the IRP work streams identified by Enbridge Gas for 2026 (section 10).

To categorize its 2026 IRP priorities, Enbridge Gas used the same work streams as in 2025:

- External Stakeholder Outreach
- Continued IRP Evaluation and Project Monitoring
- Discounted Cash Flow-Plus (DCF+) Test
- Pilot Projects
- System Pruning
- Policy Proposals
- Framework Consultation

Specific new activities identified by Enbridge Gas for 2026 include:

- Working with Posterity Group on updates to the IRP model to improve forecasting of peak hourly flow reduction potential and costs, and refining modeling assumptions based on learnings and findings from the pilot as they become available.
- Continued execution of the Southern Lake Huron IRP Pilot plan, including implementation, wind-down, and evaluation and reporting, and engaging the Working Group for input and review on these actions.

- Field implementation of the system pruning pilot, inclusive of updating and consulting with the Working Group on key elements as appropriate.
- Next steps in the IRP Framework Review, contingent on OEB direction.

Working Group members (except observers) were asked the following question:

> ***Having reviewed Enbridge Gas's description of its IRP activities in the previous year in its final 2025 IRP annual report and having also participated in the IRP Working Group, do you have any comments and/or concerns with the implementation of the IRP Framework in 2025? Do you have any comments or concerns regarding the priority IRP work streams Enbridge Gas has identified for 2026 (section 10 of the Enbridge Gas annual IRP report)?***

Working Group members generally viewed 2025 as a year of incremental but still insufficient progress on IRP implementation. Members were pleased with the much-awaited implementation of the Southern Lake Huron IRP pilot and the continued development of the system pruning pilot as important steps that are expected to yield useful learnings. However, members generally expressed ongoing frustration that IRP progress remains slower than originally contemplated, in that five years after the initial OEB-approved IRP Framework, IRP has not yet meaningfully displaced or deferred conventional gas infrastructure investment. Several members noted the persistent disagreement and lack of resolution (between Enbridge Gas and the Working Group) on core elements of the framework – particularly the DCF+ cost-effectiveness test and the overall IRP screening process – as key constraints on advancing IRP alternatives as a viable, scalable option for ratepayers.

Working Group members generally emphasized evaluation and synthesis of lessons learned from the pilots – especially the Southern Lake Huron pilot, alongside implementation and evaluation of the system pruning pilot – as the top near-term priority for 2026. Several members called for faster iteration and decision-making so learnings can translate into timely adjustments and scaling (including planning for subsequent pilots in parallel with evaluation). In addition, several members highlighted the need to address foundational analytical and policy issues that have slowed progress, including resolving or reforming the DCF+ test and examining why so few projects are meaningfully exposed to IRP evaluation. Suggested areas of focus included stronger sensitivity analysis in demand and cost modelling (to test conditions under which an

IRP alternative could be preferred and the value of deferral), greater transparency on actual facility project costs and realized demand relative to forecasts, and using the IRP Framework review to consider changes that improve regulatory certainty, accountability, and the overall speed and effectiveness of the Framework.

OEB staff will work with Enbridge Gas to develop a schedule/work plan for the Working Group based on 2026 priorities.

Comments provided by individual members can be found below in **Table 2**.
Comments from Enbridge Gas Working Group members follow in **Table 3**.

Table 2: Individual Comments of IRP Working Group Members

Working Group Member	Comments (optional)
John Dikeos (non-utility member)	It was encouraging to see movement on the long-delayed SLH pilot program in 2025. Enbridge also demonstrated progress towards the implementation of a system pruning pilot project. Although there has been a noticeable uptick in the pace of progress over the past couple years, I agree with most of the comments and concerns shared by other members of the TWG, and the pace of progress is still too slow for IRPAs to become a viable alternative that can be applied to a meaningful portion of gas infrastructure projects in the near future. In particular, the structure of the IRP framework has been hindering progress, so the ongoing review of the framework presents an important opportunity for improvement. I'm hopeful that it will be meaningly restructured to help enable success. As I noted in my feedback to Enbridge's 2024 IRP annual report, top priorities in the review of the IRP Framework should include a review of stated goals and objectives, support for the consistent and long-term valuation of GHG emissions benefits, and a requirement for Enbridge to consider stranded asset risks for new gas infrastructure projects. The IRP Framework review should also consider a nimbler process for any related pilots and projects to allow for quicker implementation and learnings and reduced risks in implementing IRPA projects. Finally, as other TWG members have stated, important changes to the DCF+ cost-effectiveness methodology for IRPA projects are needed and

	related updates to the IRP Framework could help expedite this process. Regarding the priority IRP work streams that Enbridge Gas has identified for 2026, the target sample for system pruning seems to be unnecessarily constrained, despite feedback on this point from myself and other TWG members. However, I'm hopeful that Enbridge will pivot as necessary to ensure that the system pruning pilot garners broader feedback on the potential for wider implementation. Given the extended timeline for pilot approvals and the ongoing need for learnings related to broader IRPA project implementation, I would also suggest that Enbridge start considering additional pilots, targeting potential gaps from ongoing initiatives.
Tamara Kuiken (non-utility member)	I am pleased that 2025 finally saw the implementation of an IRP pilot. While 2025 also saw extensive research into and planning for system pruning, I feel the overall timeline continues to be too slow to achieve the learnings necessary to protect ratepayers from unnecessary investments. For 2026, as mentioned by the OEB staff, I think evaluation of the IRP pilot should be of highest priority. I would also like to see changes to the process that encourage faster learnings, even at the cost of slightly increased risk, and faster implementation as new learnings come in. Specifically I'd like to see the following considered: • Changes to the framework to improve the speed of the entire process. The System Pruning scan found that regulatory uncertainty will result in delays and stakeholder opposition; I believe we're seeing that in action in Ontario. As we work to disrupt the way the natural gas industry does business, maybe we need to consider how the regulatory industry can change to more closely match the current rate of business. We are creating new processes and business models; iteration must happen faster. • Changes to the DCF+ test to make it internally consistent and logical. Cost effectiveness testing has been the number one disagreement between the TWG and EGI for the last five years. We have exhausted all paths to compromise. Per my previous bullet, changes need to be made to help resolve questions like this in a more timely manner.

	• Faster decision-making and action to quickly scale based on learnings. The initial feedback from the IRP pilot suggests success. Based on previous experience, it takes a long time (more than 1 year?) to design and plan implementation of such a pilot. I'd like to see processes in place that encourage immediate planning for the next pilot, paced to parallel the learnings received by the evaluation process as they come in. To be more specific, I'd like to see the TWG investigate and make recommendations to the OEB on how the regulatory and oversight process can be adjusted (on a pilot basis, if necessary) to allow greater innovation and faster iteration, which provides greater value for ratepayers.
Cameron Leitch (non-utility member)	I'm encouraged that the SLH IRP Pilot is progressing, but like other TWG members continue to be frustrated at the rate of progress. Most of the TWG members have been involved since inception more than 5 years ago, when direction was to identify and commence implementation of a pilot within a year. I think a majority would agree that if we could have foreseen the rate of progress 5 years out, "success" wouldn't be the first noun that comes to mind. This last sentence, like the following brief summary, mimics the same comments I'd made in the 2024 report and in years prior to that. We've spent a substantial amount of time debating the mechanisms of DCF+ with very little modification despite very little rationale for keeping things the same. But as it turns out, we needn't have spent so much time since so few investments (in this recent IRP Report, 20 of approximately 2,800) get an opportunity to be evaluated. And since Enbridge is resolved to argue the DCF+ mechanism that they have chosen when the first non-pilot IRP Alternative is brought forward (notably after it manages to "pass" the current DCF+ methodology), it will likely be some time before this debate is resolved. There have been thousands (perhaps tens of thousands) of investments in the AMPs over the past 5 years, and billions of dollars invested, all while not a single non-pilot IRP has been able to compete based on the current methodology. It seems unfathomable, but I believe there are opportunities to understand why this process has been so one-sided, and I think there is merit in the investigation of those opportunities in 2026.

	Although we have had insight into the modelling of demand, current market volatility (in particular a dramatic slowdown in new construction, considerable inflation in construction material and labour indices, and significant swings in commodity costs due to global factors and market mechanisms - particularly in the Ontario electricity market) should be reflected through the modelling of significant sensitivities. Those sensitivities should help us answer the questions "what would have to happen for an IRP Alternative to be preferred", and the corollary "what would have to happen for the Facility investment to fall out of favour". Especially with the recent uncertainty in growth, there must be a way to determine the value in deferring an investment decision. In addition to sensitizing inputs for forward-looking modelling and assessment, some insight into actual costs that Enbridge has encountered on projects (relative to budgeted costs) and what the actual incremental demand realized was compared to what was forecasted (and how close the Posterity model was to reality) based on recent investments, would give the TWG some familiarity with the level of certainty in the proposed requirements and forecasted cost for traditional facilities projects. We've spent significant time talking about IRPAs and their costs and value, but appreciably less questioning the other side, and I think that merits some investigation. Lastly, and it may be optimistic, but I hope to see a non-pilot IRPA be identified to proceed in 2026.
Chris Neme (non-utility member)	My comments on the IRP Working Group's efforts and progress in 2025 are similar to those I provided in 2024, and echo those of Jay Shepherd below. While the Working Group still does useful work, including providing input on the Lake Huron pilot and the new pruning pilot, the group has not succeeded in advancing non-pipe alternatives (NPAs) as a truly viable alternative to capital investment in Enbridge's distribution system. As Mr. Shepherd notes, five years after the Board's order in the IRP case, we have just two pilots underway while many billions of dollars have been invested in traditional infrastructure investments. I believe that this is a function of a flawed policy framework.

	That is not to say that the IRP Working Group has not provided value. I think it has. For example, some good work has been done in helping shape the Lake Huron pilot (even if it took much longer than it should have to get it launched). However, the Working Group's value is constrained by current policy. For example, despite, what I consider to be very compelling economic and policy arguments for changing key aspects of the cost-effectiveness test for NPAs (DCF+), progress on that issue has stalled and will stay that way absent new direction from the Board. I also want to observe that the sensitivity of the Company's forecast of necessary distribution system investments to changes in forecast levels of demand, which is discussed below, raises questions about whether the value of the Company's system-wide DSM programs in reducing or deferring capital investment is being adequately captured in avoided costs used to assess DSM cost-effectiveness. Given the debate that often occurs around the rate impacts of DSM, analysis of the relationship between the magnitude of projects in the AMP and load growth should be undertaken and used to estimate the value system-wide DSM provides in reducing distribution system investments and the related downward pressure on rates associated with such reductions. For 2026, the Working Group can continue to provide some value in reviewing results and synthesizing lessons learned from the two pilots and contributing to considerations of modifications to the current IRP policy framework.
Dwayne Quinn (non-utility member)	As noted in some submissions, when the Parry Sound pilot was deferred (appropriately), not only was this event a loss of one of only two pilots ordered by the Board, but also it eliminated a project that was supplied by a single source making it ideal to evaluate the system benefit of the IRP measures. It is unfortunate that in the over two years since EGI informed the TWG that the system need was deferred, there has been no advancement of a comparable pilot project. As commented on below in the Pilot project section, I believe there is a need to establish a solid initial baseline from which to evaluate the system need that is generated from a verified simulation. Once that system baseline is established, the utility can evaluate the base case, prudent facilities' investment to meet the system need. The cost of this facilities

	investment would be compared against IRPAs to support an informed decision on how to proceed.
Jay Shepherd (non-utility member)	My comments from the 2024 Report continue to be applicable today. After five years since the OEB mandate/direction, and many years of discussion before that, IRP has still not been used to delay or replace any gas infrastructure. During that period, something in the order of $10 billion or more of facilities projects have proceeded. The primary cause of this is an OEB-approved IRP methodology/framework in which each of the multiple steps is designed to screen out an IRP alternative. The result is that none remain viable; all are screened out. As long as that continues to be true, Enbridge will continue to successfully prevent, delay, and avoid the implementation of any alternatives to building conventional gas distribution rate base. The current IRP Framework Review will, I hope, allow for a broader discussion of other ways to move IRP forward, with the goal of making the energy services provided to Ontario residents more economic and sustainable for the long term. In the meantime, the impact of the Working Group, while still valuable, is somewhat limited. Of significant concern is that Enbridge Gas has consistently refused to provide Working Group members with access to the several models on which they rely heavily. This is surprising given that some Working Group members have considerable experience with these types of models. It appears to me to be inefficient to delay disclosure of those models until a formal regulatory proceeding with multiple parties, when they will likely be produced by order, and their review at that time will delay and complicate the proceeding. This refusal raises the possibility that these models may be poorly designed, biased, or otherwise embarrassing to Enbridge. It is noteworthy that Enbridge finally shared one of the models, the ETEE model, only after being called out for failing to do so in these comments. Since making my original comments, I have seen the Enbridge comments, which appear to be solely directed at seeking to rebut everything the non-utility members have said

	in their comments. Most striking is the statement that screening out all IRPAs should be considered a successful use of the IRP Framework. This reinforces my previously stated view that Enbridge will not implement any meaningful IRPAs until they suffer consequences for failure to do so, of which the most useful consequence would be to have some or all of the risk of stranded or underutilized facilities investments fall on the shareholders rather than the ratepayers.
Mike Parkes/ Stephanie Cheng (OEB staff representatives)	**Comments and/or concerns with the implementation of the IRP Framework in 2025**: • 2025 saw encouraging developments with the Southern Lake Huron IRP pilot coming to market, and the approach to a system pruning pilot being developed (for implementation in 2026). Both of these pilots should provide useful learnings regarding IRP. The Working Group played an important role in providing input on the design of both of these pilots. • The OEB released an OEB staff discussion paper in October 2025 assessing progress implementing the IRP Framework and proposing updates to the IRP Framework. Taken together, these proposals are intended to continue to drive the adoption of the most prudent infrastructure or IRP alternative to meet a given system need, while improving the IRP value-to-effort ratio and positioning the natural gas sector to quickly and effectively adapt to various potential future scenarios. Input from the Working Group in 2025 was helpful to OEB staff in refining the proposals in the discussion paper. OEB staff does not have any additional comments or specific concerns with the implementation of the IRP Framework in 2025. **Comments or concerns regarding the priority IRP work streams Enbridge Gas has identified for 2026 (section 10 of the Enbridge Gas annual IRP report)**: • Of the noted priority IRP work streams, continued work on implementing and evaluating the two pilots (Southern Lake Huron and system pruning) should be the highest operational priority, and is an area where input from the Working Group can add significant value. • In addition, the OEB's direction for Enbridge Gas to file an updated IRP Framework for adjudicative review will also impact the priority IRP work streams for 2026.

	Enbridge Gas had previously indicated plans to conduct an updated IRP jurisdictional scan, with a contributing role for the IRP Working Group (similar to the approach taken for the completed system pruning jurisdictional scan described in the IRP Annual Report). OEB staff believes this scan would be a valuable input for the IRP Framework adjudicative proceeding and encourages Enbridge Gas to proceed with it, including the proposed role for the Working Group. The updated IRP Framework will likely include requirements for Enbridge Gas to develop and file an Implementation Plan as a second phase of the IRP Framework proceeding. OEB staff expects that Enbridge Gas will seek input from the IRP Working Group on the draft Implementation Plan (particularly technical aspects of the plan) before it is reviewed by the OEB. • It is also expected that supporting IRP policy/guidance documents developed by Enbridge Gas would be filed as part of the Implementation Plan approval request. The IRP model and methodology developed by Posterity Group and used by Enbridge Gas to forecast peak hourly flow reduction potential and costs from IRP Alternatives (discussed in Section 10 of the Enbridge Gas annual IRP report) is one specific guidance document which OEB staff encourages Enbridge Gas to work with the IRP Working Group to review and refine before it is considered in the adjudicative proceeding.

Table 3: Comments of Enbridge Gas IRP Working Group Members

Working Group Member	Comments (optional)
Alison Moore/ Whitney Wong/ Helen Tong (Enbridge Gas representatives)	Pilot Projects Enbridge Gas agrees with member comments that implementation of the SLH Pilot Project and System Pruning Pilot is a high priority for 2026. TWG members expressed encouragement regarding the advancement of the Pilots, while also noting frustration with the delay for the SLH Pilot Project relative to the deployment timing in the IRP Framework. While the timing of the regulatory proceeding for the updated SLH Pilot Project Application was outside the

	Company's control, Enbridge Gas took proactive steps in advance of the OEB issuing its Decision to expedite implementation where possible. This included moving forward with incremental resourcing required for the pilot, initiating activities required to retain an evaluation contractor, and engaging larger commercial and industrial customers in the pilot area in a targeted effort to identify potential participants to expedite the implementation of individualized hourly metering. For the System Pruning Pilot, Enbridge Gas has met the milestone dates established in the Rebasing Phase 2 Settlement Agreement and conducted extensive consultation with the TWG. Enbridge Gas has, and will continue to, consult with the TWG for input as implementation and evaluation of the pilots progress. In response to a member's suggestion of establishing a solid initial baseline for the SLH Pilot Project, Enbridge Gas notes that the evaluation methodology considers detailed customer-level data, aggregated to establish an appropriate baseline, as outlined in the evaluation plan. This approach provides the information required to assess system level impacts of ETEE and DR on peak demand. System level data is not available or required to meet the pilot objectives, as previously discussed with the TWG. While the pilot is expected to provide insights that are applicable to similar customer segments across the Enbridge Gas system, application of these learnings to specific system constraints will be dependent on system characteristics and may require appropriate scaling. As such, the existence of a specific facility need or system constraint within the pilot area is not required to achieve the objectives of the Pilot Project. With respect to member comments on considering additional pilots more broadly, Enbridge Gas maintains its view that it is not efficient or appropriate to proceed with consideration of another IRP Pilot Project while the OEB's IRP Framework Review is underway. This position is consistent with OEB's Findings in the Motion to Review Decision, which varied the March 27,2025 Decision to remove the requirement for Enbridge Gas to consult with the TWG on a potential second IRP pilot as part of the SLH Pilot Project proceeding. The OEB found that it would not be efficient or cost-effective for Enbridge Gas and TWG members to begin discussions on a second pilot project in parallel with the IRP Framework

	Review and stated that matters related to any further IRP pilot projects are to be addressed through the Framework Review.[1] IRP Framework Review Multiple members commented on the structure of the IRP Framework and the opportunity to evolve it through the IRP Framework Review proceeding. Enbridge Gas agrees on the importance of ensuring clarity in IRP objectives and policies. However, consistent with its comments from 2024, Enbridge Gas does not agree that IRP success or progress should be assessed based on the implementation of non-pilot IRP alternatives, as this does not reflect whether the IRP evaluation process has been properly applied in accordance with the Framework. The purpose of the IRP Framework Review, and objective of IRP more broadly, is not to maximize the number of IRP alternatives implemented, but rather to ensure the most appropriate solution is identified to address system needs. The outcome of this process, where an IRP alternative is not selected as the preferred alternative, represents a finding as opposed to a failure in the IRP Framework or its implementation. In 2025, Enbridge Gas completed the IRP assessment of all investments in the AMP with a defined scope. Enbridge Gas considers the IRP Framework Review an opportunity to improve regulatory and operational efficiency, including a “fit-for-purpose” approach informed by experience gained through implementing the IRP assessment process. The IRP Framework Review will also provide the opportunity to ensure IRP is aligned with Ontario government policy, consistent with OEB direction (EB-2025-0125), which notes that Enbridge Gas’s updated IRP Framework application should consider relevant elements of Ontario’s Integrated Energy Plan.[2] Enbridge Gas does not agree with member comments that the updated IRP Framework should include long-term valuation of GHG emissions benefits or consideration of stranded asset risks and does not agree with member criticisms of the DCF+ cost-effectiveness methodology. However, Enbridge Gas considers these matters most appropriately addressed through the IRP Framework Review proceeding rather than through continued TWG consultation.

	With respect to stranded asset risk, demand forecasting sensitivities and forecast validation, Enbridge Gas considers the rebasing proceeding to be the appropriate forum to assess the demand forecasting methodology, capital planning and related assumptions. Addressing these issues across multiple proceedings would be inefficient and may result in inconsistent and/or incomplete considerations. Within the IRP economic evaluation process, Enbridge Gas has introduced a single-variable cost sensitivity analysis to support comparison of alternatives informed by input from the TWG in 2025. This analysis considers the degree to which the cost of alternatives would need to change to achieve parity with the preferred alternatives on a DCF+ Phase 1 net present value basis. Enbridge Gas is developing a template to support the economic evaluation of IRP alternatives, inclusive of this information, which will be shared with the TWG in 2026. Enbridge Gas also acknowledges comments regarding the anticipated development of an IRP Implementation Plan as a subsequent phase of the IRP Framework Review, including the opportunity for TWG input into the development and refinement of supporting elements of the plan. Enbridge Gas agrees that TWG engagement will be included in this process, recognizing that such engagement should not duplicate prior consultations. For example, extensive consultation has already occurred on the DCF+ test and Enbridge Gas has incorporated modifications that it has determined are appropriate. With respect to jurisdictional review, Enbridge Gas agrees that such information can be useful, provided it considers the proper context in relation to Ontario (such as differences in policy objectives, regulatory mandates, system characteristics, etc.). Given the infancy of system pruning activities, the system pruning jurisdictional scan prepared by DNV was broader in scope and incorporated relevant insights on non-pipe alternative programs, policies, and framework level considerations. However, in the context of IRP objectives and Ontario's public policy framework, the scan reported a key distinction: identified jurisdictions[3] that are considering, planning or implementing non-pipe alternatives are primarily driven by decarbonization and climate goals, which reflect policy contexts that differ from Ontario.

	Additional jurisdictional review will be considered alongside the next steps in the IRP Framework Review proceeding. ETEE Model Enbridge Gas does not agree with the characterization that it has consistently refused to provide TWG members with access to its models. During TWG Meeting #56 (in June 2025), Enbridge Gas provided a detailed overview of its internal ETEE model, including the methodology, key assumptions and formulas underpinning its application. Enbridge Gas subsequently provided a follow-up at TWG Meeting #59 confirming the consistency of the forecasting approach, the basis for the peak-to-annual savings factor, and the treatment of load diversification. Provision of the model was not discussed or requested during 2025 consultations. At TWG Meeting #63 (in April 2026), a TWG member requested access to the model. Enbridge Gas explained that its approach had reflected its objective to receive input on the methodology of the model and input on assumptions, recognizing that the model is an analytical tool requiring appropriate context and governance for use, including within Enbridge Gas. Enbridge Gas does not accept that its consultation approach reflects concerns with the model's design or application. At Meeting #63, Enbridge Gas committed to considering the request for a copy of the model. Following consideration of TWG feedback, Enbridge Gas provided the ETEE model to the TWG in May 2026. This reflects Enbridge Gas's continued commitment to transparency, responsiveness to TWG input, and meaningful engagement. [1] EB-2025-0333, Decision and Order - Motion to Review Decision on Integrated Resource Planning Pilot Project, May 14, 2026 [2] EB-2025-0125, Next Steps - Integrated Resource Planning Framework Review for Enbridge Gas, April 28, 2026 [3] The exceptions were Oklahoma at the "considering" phase with a primary economic driver associated with exploring a roadmap of creating a hydrogen economy and Denmark at the "implementing" phase with a primary driver on reducing reliance on Russian gas imports.

3. Description of Key Working Group Activities in 2025

Enbridge Gas's IRP priorities for 2025 were previously identified in its 2024 IRP annual report. These included:

- External Stakeholder Outreach
- Continued IRP Evaluation
- Discounted Cash Flow-Plus (DCF+) Test
- Pilot Projects
- System Pruning
- Policy Proposals (for non-pilot IRP Plans)
- Framework Consultation

Progress on each of these items was subsequently discussed in some form with the Working Group in 2025, with particular emphasis placed on the two pilots (Southern Lake Huron Pilot and System Pruning Pilot). Progress on these pilots (implementation and evaluation) had been identified by Working Group members in the 2024 IRP Working Group report as the top IRP priority for 2025. Working Group discussion to inform the OEB staff discussion paper on the IRP Framework review was also a focus. A high-level summary of key topics discussed by the IRP Working Group is provided in the subsections below. Readers can refer to the meeting folders on the OEB's Engage with Us IRP webpage[4] for meeting materials and meeting notes summarizing key discussion points and outcomes. Refer to Table 4 below for a summary of meeting dates and key topics discussed at each meeting.

Table 4: Summary of Working Group Meetings and Key Topics Discussed

Meeting Date	Key Topics Discussed
June 25, 2025	• System Pruning Pilot approach – addressing Working Group feedback • IRP incentives – review types of incentive mechanisms • IRP Assessment – presentation on input assumptions and methodology of the demand-side (Enhanced Targeted Energy Efficiency (ETEE) / Demand Response (DR)) IRPA Model

[4] https://engagewithus.oeb.ca/irp

July 30, 2025	• IRP Pilots Update (Southern Lake Huron and System Pruning) • System Pruning jurisdictional scan • IRP Evaluation (Status update, DCF+ results and interpretation, DCF+ update) • IRP Framework Review (Electrification)
September 3, 2025	• IRP Framework Review (Future Role of Working Group)
September 25, 2025	• IRP Shareholder Incentive Mechanism Proposal
October 29, 2025	• Southern Lake Huron Pilot Update (pilot offers, marketing, evaluation, stakeholder engagement, measurement update, evaluation, measurement & verification (EM&V) and data analysis) • IRP Jurisdictional Scan • Stakeholder Update
December 3, 2025	• System Pruning Pilot update

3.1. External Stakeholder Outreach

In November 2025, Enbridge Gas shared a draft of its Fall 2025 IRP Regional webinar slide deck with the Working Group, ahead of the public webinars scheduled for December 1 and December 11, 2025. Working Group members were invited to provide written feedback on the draft materials, which would be considered by Enbridge Gas in finalizing its stakeholder engagement tips and materials; however, no members provided comments, and Enbridge Gas subsequently finalized materials and held the public webinars.

3.2. IRP Evaluation Process

In 2025, Enbridge Gas continued discussions with the Working Group on refining aspects of its IRP evaluation process, and shared results of completed IRP evaluations for a subset of projects selected to illustrate the application of the DCF+ methodology with differing facility cost and demand growth characteristics. The Working Group provided input on two key topics:

- **Improving the methodology and documentation by which energy efficiency IRP alternatives (ETEE and DR measures) are assessed**. Enbridge Gas sought feedback from the Working Group on the methodology and input assumptions of an updated demand-side IRPA regional model, which forecasts IRP participation, costs, and peak demand savings, making use of forecasts and participation data for Enbridge Gas's existing demand-side management (DSM) programs. This model will be used as an input in both the technical evaluation and economic evaluation stages of IRP evaluation going forward. The

model was not shared with the Working Group, but members provided feedback on the inputs and assumptions for Enbridge Gas's consideration. Members raised questions about factors such as: the assumptions involved in forecasting IRP participation based on the previous level of participation in DSM programs, how to predict participation levels that would result from customer incentive levels higher than those previously used, how the accuracy of the model will be assessed and calibrated, and the exclusion of contract customers from the model. Enbridge Gas provided clarification and subsequently made several minor updates to its model based on Working Group input, including adjusting the scaling based on regional consumption and ETEE adoption rates. The issues raised by members have not been fully resolved; Enbridge Gas noted that the model is likely to be refined and improved based on actual IRP project results, including the Southern Lake Huron pilot.

The IRP regional model uses information from and complements the IRP model previously developed by the Posterity Group that has been used by Enbridge Gas at the technical evaluation stage to assess whether an IRP alternative is technically feasible. In response to previous discussions with the Working Group (covered in a previous report), Enbridge Gas has committed to work with the Posterity Group to update and publicly document the methodology for this IRP model. This is expected to provide other interested parties with a better understanding of the modeling approach used in technical potential evaluations.

- **Updated IRP evaluation results of projects in Enbridge Gas's Asset Management Plan (AMP) in 2026, factoring in newly available and relevant information, data, and insights including system reinforcement plan updates.** Summaries of updated evaluation results were shared with the Working Group for questions and comments. A Working Group member noted concerns with the sensitivity of the AMP to the growth forecast, and that many growth projects that were in the previous version of the AMP had been removed from the updated version, highlighting the significant uncertainty associated with the growth forecast. Enbridge Gas noted that changes in the growth forecasts and the associated investment project scopes are a result of many factors, such as updates to customer forecasts/demands/attachments and that projects are progressively refined as projects progress towards their in-service date. Enbridge Gas subsequently provided details on the specific changes to the growth forecast that led to the updated results. The larger issue of how the IRP Assessment process should account for a changing demand forecast remains a concern, and is noted in the OEB staff discussion paper on the IRP Framework review.

3.3. Discounted Cash Flow-Plus Test

In 2025, Enbridge Gas presented IRP economic evaluation (DCF+) results for four new projects to the Working Group. The analysis compared project cost, results of the individual phases, combined Phase 1 and Phase 2 Net Present Value, and relative bill impact between Facility Alternatives and IRP Alternatives. The analysis also looked at whether the demand driving the project need was expected to persist and the timing of the project need, which impacted whether a final decision (Facility Alternative or IRP Alternative) was needed or whether the need could continue to be monitored. The analysis indicated that a Facility Alternative was the preferred alternative for three of the projects, while a supply side IRP Alternative (compressed natural gas) was the preferred alternative for one project. The timing of this system need is not until 2029, so Enbridge Gas will not immediately implement the supply-side IRP Alternative. Enbridge Gas will continue to monitor the system need in the following year and reassess as required, to allow for the possibility of changes to the demand forecast that could impact the system need. Enbridge Gas subsequently noted that compressed natural gas solutions can be deployed in a relatively short timeframe (i.e. deployed within the same year as the required facility in-service date).

Enbridge Gas also used this discussion to provide an update on its perspective on the broader issues the Working Group had identified with the DCF+ test, including concerns regarding the exclusion of carbon costs and the methodology for capturing broader economic impacts through a GDP multiplier. Despite the Working Group's disagreement with the substance of if and how phase 3 societal impacts are captured and how its approach aligns with the OEB's orders, Enbridge Gas maintained that the DCF+ test appropriately reflects economic impacts within the OEB's mandate and that Working Group feedback has been considered.

The next step is for the OEB to review Enbridge Gas's updated DCF+ methodology as part of Enbridge Gas's first non-pilot IRP plan application, which will provide an opportunity for this question to be adjudicated.

3.4. Southern Lake Huron Pilot – Implementation and Evaluation

The 2021 IRP Framework required Enbridge Gas to develop and implement two IRP pilot projects. In July 2023, Enbridge Gas applied to the OEB for approval of two IRP pilot projects, but one of the pilots was later withdrawn. The other pilot, the Southern Lake Huron Pilot, was approved by the OEB on March 27, 2025, with certain modifications. While certain aspects of

the OEB decision have been appealed and are under review, Enbridge Gas has proceeded to implement most aspects of the approved pilot. The pilot was brought to market in 2025 under the name “Sarnia Saves”, offering enhanced customer incentives for energy efficiency measures that reduce peak demand, and a new demand response program for residential customers.

Enbridge Gas provided the Working Group with updates on the pilot for feedback. These updates covered the design and implementation of residential, commercial, and industrial pilot offerings (including lessons learned), evaluation, measurement, and verification of peak savings, marketing plan, and stakeholder engagement.

Progress related to the Pilot’s two primary objectives is summarized below:

Objective 1: Develop an understanding of how ETEE programs and DR programs impact peak hour flow/demand.

- Enbridge Gas selected Dunsky Energy and Climate Advisors as the external consultant to assist in assessing the peak demand impact of the pilot. A draft EM&V plan was expected to be shared with the Working Group for feedback in late 2025, but this was postponed to early 2026.
- Enbridge Gas shared its preliminary in-house hourly load regression analysis approach which will be used as an input to assess peak demand impacts (Dunsky Energy and Climate Advisors are also expected to assess and support the development of this internal tool). The Working Group reviewed and provided comments on Enbridge Gas’s preliminary approach, including which variables to track and suggestions on how to test the tool for reasonableness. The Working Group also recommended collecting and retaining as much data as possible, as it is easier to exclude unnecessary data later than to retroactively collect data related to previously excluded variables.
- Enbridge Gas will take the Working Group’s feedback into consideration in finalizing its approach to data collection and EM&V.

Objective 2: Develop an understanding of how to design, deploy, and evaluate ETEE and residential DR programs.

- Enbridge Gas provided an update on design and implementation of the Southern Lake Huron Pilot (“Sarnia Saves” program), which generally aligns with the project plan outlined in the 2025 IRP annual report but includes minor updates informed by Working

Group feedback. The Working Group provided additional input on marketing and stakeholdering activities and considerations for both residential and commercial pilot offers, as well as tips and considerations on the use of Brightlync meters for hourly data collection. A Working Group member noted concerns about whether an appropriate baseline can be established and whether the pilot's results will be transferable to other systems, given Southern Lake Huron's multi-feed network and limited flow data at the feed points which makes it challenging to quantify system-level benefits.

- Enbridge Gas reported stable and consistent engagement from both residential and commercial customer leads. Given the high interest and early success, Working Group members raised questions about exploring opportunities to expand customer participation, while recognizing the pilot's budget and scope constraints.
- A member of the Working Group served as a representative to review and provide feedback on draft customer survey and interview guides. These tools will then be finalized and used by the program evaluator to gain a better understanding of the experience of those involved in the Southern Lake Huron pilot. Baseline surveys were completed in September 2025. Initial Enbridge Gas staff interviews were conducted in July 2025, followed by delivery agent and energy advisor interviews in December 2025. Residential and commercial participant interviews are expected to take place in 2026.

It is expected that Enbridge Gas will continue to engage with the Working Group to review and provide input on project plan, implementation, and evaluation elements throughout the Southern Lake Huron Pilot.

3.5. System Pruning Pilot and Jurisdictional Scan

As part of the Settlement Agreement for Phase 2 of Enbridge Gas's rebasing application, Enbridge Gas committed to conducting a system pruning pilot (i.e., incenting customers to voluntarily exit the gas system as an alternative to replacing gas infrastructure), with the approach to be developed in consultation with the IRP Working Group. Implementation of one or two system pruning pilots was expected to begin by the end of Q1 of 2026.

Throughout 2025, Enbridge Gas worked closely with the Working Group (and a temporary system pruning subgroup of the Working Group) to refine a draft "approach" document for the system pruning pilot. This work was mostly undertaken in the first half of 2025 and was documented in last year's Working Group annual report.

In late June 2025, the approach document was finalized. It outlines key elements of the pilot including objectives, selection criteria for system renewal projects potentially suitable for system pruning, the customer engagement plan and offers, customer choice (i.e., how the pilot will address circumstances where customers do not want to disconnect from the natural gas system, or wish to reconnect after participation in the pilot), a stakeholder engagement plan, the approach to program delivery, an implementation plan, and evaluation strategy. Proposed revisions to the document were reviewed by the full Working Group in June 2025 with the intent of enabling Enbridge Gas to incorporate member feedback into the plan. While the Working Group did not formally approve the document, it supported proceeding with it as a reasonable initial approach, subject to ongoing review and further Working Group input as the pilot is executed and lessons are learnt. The system pruning approach document was filed by Enbridge Gas with the OEB on July 4, 2025.

To support the development of the system pruning pilot, DNV was engaged as an external consultant to conduct a jurisdictional scan on system pruning. In the first half of 2025, the system pruning subgroup provided extensive feedback to DNV to inform the development of this report. In July 2025, DNV provided the full Working Group with an update on revisions made to the draft jurisdictional scan report in response to member feedback. The report was published in August 2025.

Following the filing of the system pruning approach document, Enbridge Gas continued to bring the pilot closer to implementation, including identifying target project areas and selecting a contractor to deliver the pilot. In July 2025, the Working Group reviewed and provided feedback on a customer outreach pre-screen survey that would be used to gauge customer interest in participating in a system pruning project, including suggestions related to survey language and delivery methods. Enbridge Gas updated the pre-screen survey to incorporate feedback provided by the Working Group, and proceeded with the pre-screen phase of the pilot implementation to a subset of customers in target project areas that met the defined criteria. In December 2025, Enbridge Gas shared the survey results and discussed how the findings would inform field implementation. In response, the Working Group provided feedback on several aspects of the pilot design including customer outreach approach and interpretation of survey results (e.g., cautioning against interpreting non-response as lack of interest), the importance of targeting high-value opportunities (e.g., expanding outreach beyond the initial six interested customers to include one or two neighboring customers or small clusters in parallel with proceeding with the initial participants), consideration of commercial and mixed-use

opportunities, and the value of testing different marketing and outreach methods through multi-modal and repeated engagement. Members also emphasized that messaging should clearly originate from Enbridge Gas to enhance legitimacy and trust and should motivate customers by communicating potential bill impacts or savings, potentially supported by modest financial incentives to increase engagement. Enbridge Gas will proceed to next steps in pilot implementation with the six interested customers, which was supported by the Working Group. Enbridge Gas will also consider the Working Group's suggestions regarding conducting additional outreach, informed by the insights gained through engagement with the six targeted candidates. Working Group feedback noted considerations of increasing pilot participant numbers to improve the likelihood that the pilot will provide meaningful learnings.

3.6. Non-Pilot IRP Plan Policy Proposals – Incentive Mechanisms

In 2023, the Working Group discussed IRP policy proposals related to attribution of savings between Demand-Side Management programs and IRP Plans, shareholder incentives and performance metrics, IRP Deferral Accounts, and management of risk associated with IRP implementation. At the time, Enbridge Gas expected to consider perspectives of the Working Group and then file proposals on these topics for the OEB's consideration as part of Enbridge Gas's first non-pilot IRP plan. Enbridge Gas did not have a viable non-pilot IRP plan application to file with the OEB in 2024, and so other topics took priority and these policy discussions with the Working Group were put on hold in 2024. However, the Phase 2 rebasing settlement approved by the OEB in November 2024[5] established a new commitment for Enbridge Gas to file an application that includes a proposal and request for approval of an IRP incentive mechanism by the end of November 2025, resulting in the discussion on shareholder incentives resuming.

In June 2025, Enbridge Gas provided the Working Group with a recap of the incentive discussions that took place in 2023, highlighting the pros and cons of each of the types of incentive mechanism discussed. Enbridge Gas then shared its initial findings on how shareholder incentive mechanisms are used in other jurisdictions. The Working Group noted that the analysis to date may not sufficiently consider the level of incentive required to meaningfully motivate Enbridge Gas's shareholders to pursue IRP alternatives instead of traditional rate-base-eligible infrastructure. Acknowledging the conceptual goal of aligning shareholder interests with prudent IRP outcomes, some Working Group members expressed

[5] Decision on Settlement Proposal and Interim Rate Order, November 29, 2024, EB-2024-0111

skepticism that the OEB would ever approve an IRP incentive mechanism that provides returns comparable to those available through rate-basing capital investments.

In September 2025, Enbridge Gas brought the Working Group a specific incentive proposal for discussion. Under this proposal, Enbridge Gas would capitalize the O&M costs of an IRP Plan and incorporate a shared savings mechanism to retain some of the cost savings of the IRP Plan relative to the traditional facilities investment. A Working Group member noted that the choice of a shared savings mechanism is aligned with the IRP Framework's emphasis on cost-effectiveness testing and prioritizes cost savings from IRP. However, Working Group members noted several concerns with the specific incentive design, e.g., questioning the premise that the return to shareholders needs to be the same for an IRP Alternative as for a higher-cost Facility Alternative (i.e., a traditional infrastructure solution), noting that the percentage of savings retained by the utility is lower in some other jurisdictions that use a shared savings mechanism, and noting the risk that Enbridge Gas may overstate the expected cost of a traditional solution in order to be eligible for a larger incentive.

On November 4, 2025, Enbridge Gas filed its IRP incentive mechanism application (which was based on the incentive proposal discussed with the Working Group) but requested that the application be put in abeyance until the outcome of the IRP Framework Review proceeding is known. On December 22, 2025, the OEB granted the request, and the application remains in abeyance.[6]

3.7. IRP Framework Review

In March 2025, the OEB announced that it was initiating a consultation to review the IRP Framework. As part of the consultation, the OEB noted that it would consider several key items including:

- How the Framework would be best constituted to allow for broad, flexible implementation that can adapt at a pace that supports innovation,
- The OEB's expectations and approach to oversight of innovation-related IRP proposals,

[6] EB-2025-0292

- Expectations for natural gas distributors regarding electrification as an IRP alternative, including how electricity availability issues should be considered if electrification is being proposed as an IRP alternative, and
- Opportunities to improve the effectiveness and efficiency of the Framework.

OEB staff consulted with the Working Group to inform development of OEB staff's IRP Framework Review discussion paper. In the first half of 2025, the Working Group discussed the purpose and form of the IRP Framework, the approach to technical evaluation of the viability of IRP alternatives, and how the Framework should address innovation. In July and September 2025, the Working Group continued its IRP Framework Review discussions, focusing on the role of electrification, the proposal for a 3-year adjudicated IRP implementation plan, and how the role of the IRP Working Group would evolve with the framework.

Regarding electrification, Working Group members shared a variety of differing views on its appropriate role within IRP. Members generally envisioned electrification as one IRP alternative to be considered when seeking to address a system need. However, there was some concern with the idea of Enbridge Gas acting as the gatekeeper or delivery agent for electrification initiatives due to potential conflict of interest. Some members proposed the IESO or local electric utilities should lead electrification efforts with Enbridge Gas advancing gas infrastructure where electrical options are insufficient. Enbridge Gas emphasized that the IRP Framework is intended to be neutral and cautioned against perceived bias toward IRP alternatives over traditional gas infrastructure. Enbridge Gas noted there is a need for full comparisons of all ratepayer costs, as well as consideration of policy guidance in the Integrated Energy Plan on the future role of natural gas, while some members noted that existing cost analyses may understate select gas infrastructure-related costs such as costs associated with carbon emissions and stranded asset risk.

Regarding the proposal for an IRP implementation plan to be adjudicated every 3 years with annual informational updates, some Working Group members supported this approach as a way to create clearer accountability (through adjudicative oversight), while providing flexibility in the Plan approval for a more nimble approach to make program changes in the years between adjudication. Another member favored a more frequent rolling plan with some adjudicative oversight each year to enhance forward-looking transparency, cautioning that greater procedural flexibility must be balanced with safeguards to address ratepayer concerns and ensure front-end oversight rather than reliance on after-the-fact prudence reviews.

Discussion on the role of the IRP Working Group reflected Working Group member concerns about the Working Group's limited influence and impact under the current IRP Framework, underscoring the need for adjudicated processes to drive accountability. Various members observed that Enbridge Gas appears to determine its preferred IRP direction internally then seeks Working Group input selectively, which, while useful, falls short of a fully collaborative process. Some members noted that slow progress on IRP is driven more by the absence of clear and supportive policy direction that creates a strong business case or policy rationale for IRP, rather than by any shortcoming of the Working Group's role or processes.

In October 2025, OEB staff released a staff discussion paper with proposals for updating the IRP Framework, informed by the input previously provided by the Working Group.

Appendix F: IRP Assessment Screening and Evaluation Guidelines

IRP Assessment Screening and Evaluation Guidelines

Version Date: 2026

Introduction

This document outlines the IRP Assessment Screening Criteria and rationale used in the IRP Evaluation process and is updated on an annual basis to reflect process updates and learnings gained through the year. Previous versions were filed in past IRP Annual Reports, as well as at EB-2022-0200, JT 5.36 Attachment 2 and examples of the detailed technical evaluation form can be found at EB-2022-0220, JT 5.36 Attachment 3 and 4.

On an annual basis, Enbridge Gas files an Asset Management Plan ("AMP") or AMP Addendum. To ensure the most optimal facility alternative is included in the AMP, and prior to the IRP assessment process, Enbridge Gas routinely considers a wide range of traditional facility alternatives when conducting project scoping of facility needs, where applicable. Investments are subsequently reviewed as part of the Asset Investment Planning & Management ("AIPM") process for IRP alternatives ("IRPAs") which are assessed against the project scope where traditional facility alternatives have already been considered. This process can be iterative due to the dynamic nature of facility planning and changes to demand forecasts. Therefore, project scopes for both traditional and IRP alternatives may require reassessment to ensure the most up to date information is captured.[57]

The IRP Assessment Screening and Evaluation criteria described in this document are conducted using the direction and guiding principles provided by the OEB in its IRP Decision and Order (EB-2020-0091). The investments considered as part of this binary screening and technical screening and evaluation process include investments within the AMP and are limited to regulated Enbridge Gas investments. In future AMP investment assessments, Enbridge Gas will systematically apply these learnings to allow focus on the geographic areas and investment types that are most likely to yield an IRP Plan that is both technically and economically feasible.

IRP Assessment Process Overview

1. **Initial Screening**
   The evaluation process began with removing non-gas-carrying asset investments from the list of AMP Addendum 2026 investments that would proceed to the binary screening phase.

2. **Binary Screening**
   Investments are screened out as per Section 5.2 of the IRP Framework. Investments under the Asset Class of Customer Connections are also screened out as part of Binary Screening.

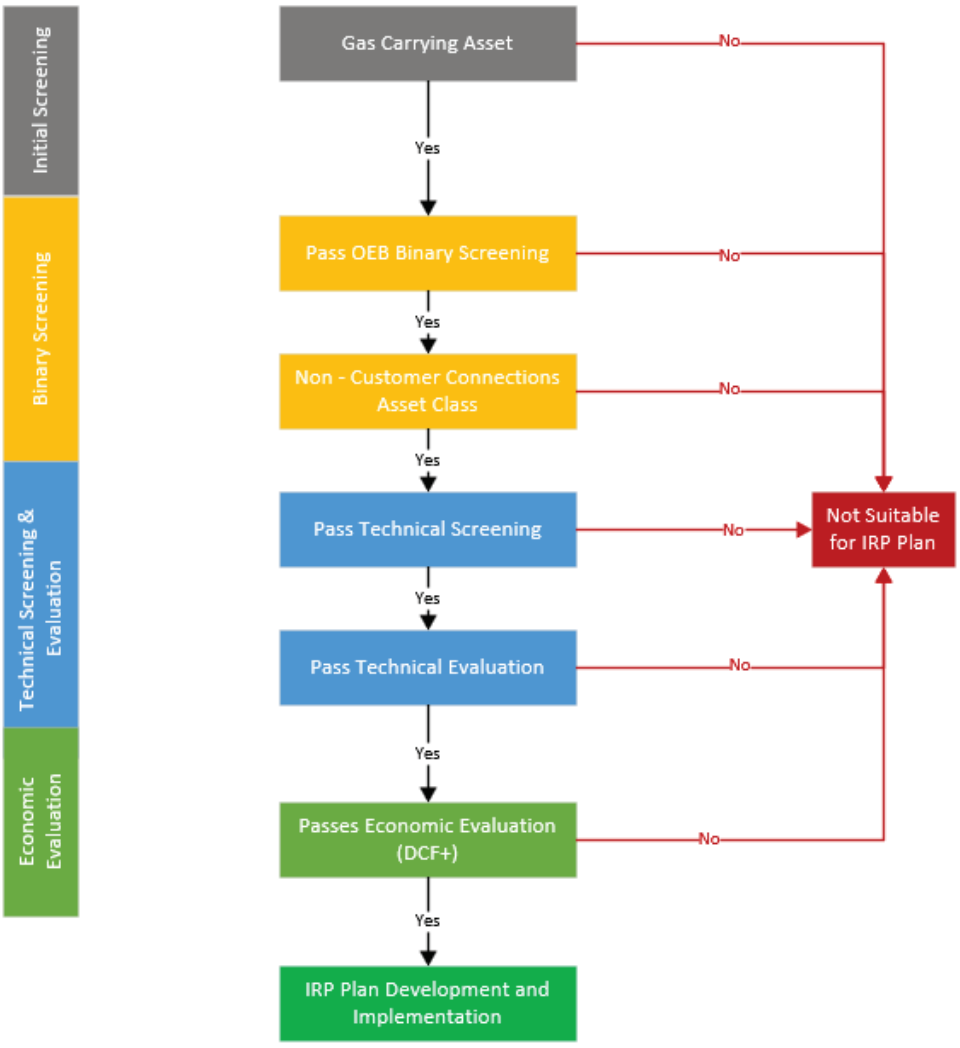
3. **Technical Screening & Evaluation**
   Investments undergo an initial technical screening to determine whether a detailed technical evaluation is required.

   Investments that have passed technical screening will be evaluated for whether an investment could have a technically feasible IRPA(s). To assess the technical potential of IRPAs to meet a system need, Enbridge Gas calculates the required demand reduction and/or incremental supply by determining the difference between the required and current system capacity. Where IRPAs have the technical potential to offset the required capacity through either a reduction in the design hour/day demand or incremental supply within the required timeframe to address the system constraint, and without compromising the safety and reliability of the system, these investments pass the technical evaluation.

4. **Economic Evaluation**
   Investments that have passed technical evaluation will be economically evaluated using the DCF+ test. The DCF+ test compares each technically feasible IRPA and the identified baseline facility project to a 'do nothing' scenario. The DCF+ results for the IRPAs and the baseline facility alternative are then compared to one another to determine the optimal alternative or combination of alternatives to meet the system need. If it is determined that the most optimal option includes one or more IRPAs, an IRPA Plan will be developed where applicable.

[57] IRP Annual Report, Section 7, Table 7.1 provides a "Summary of Facility and IRP Alternatives"

Figure 1 – IRP Assessment Flow Chart



Initial Screening

Ahead of the binary screening, investments in non-gas carrying assets were removed. These investments are in the "Real Estate & Workplace Services", "Fleet & Equipment", and "Technology & Information Services" asset classes.

Binary Screening

All remaining investments are subject to the binary screen criteria as provided by the OEB. Investments that satisfy the binary screening criteria were removed from further evaluation.

- ***Investments deemed Emergent Safety Issue***
  "If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and Enbridge Gas's broader transmission and distribution systems.

Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis".[58]

- ***Investments failing based on Timing***
  "If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need".[59]

- ***Investments failing based on Cost ($) Threshold***
  "If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then an IRP evaluation is not required".[60] On September 24,2024, the OEB released new Filing Requirements applicable for exemption on hydrocarbon line projects that cost between $2M and $10M, where information on project need and alternatives are not required.[61] The new exemption requirements for facility projects with costs between $2M and $10M are considered a legislative change and thus, does not impact the Binary Screening cost threshold. Therefore, Enbridge Gas continues to apply a cost threshold of $2M to screen replacement or relocation projects out at this stage, as well as any associated main replacement/relocation programmatic spend.

- ***Customer-Specific Build***
  "If an identified system constraint/need has been underpinned by a specific customer's (or group of customers') clear request for a facility option and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required".[62]

- ***Community Expansion & Economic Development:***
  "If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required."[63] As noted in the AMP[64], Community Expansion and Economic Development projects are not included in the AMP and therefore no associated IRP evaluation is conducted.

Additionally, investments with the asset class of "Customer Connections" will be screened out at the Binary Screening stage. *Customer Connection-related projects are required to serve new customers connected in accordance with guidelines of EBO 188. The OEB concluded that as part of the first-generation IRP Framework it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs.*

The investments in the customer connections asset class are related to costs associated with serving new customers, including materials and installation of distribution mains, services and regulating equipment. Enbridge Gas determined that implementing an IRPA could not reduce the size of the assets, as these cannot be further downsized. In addition, there are no non-gas IRPAs available within the current IRP Framework that can be offered to avoid the customer connection service being requested. Therefore, investments under this category should be screened out through the binary screening phase, in advance of technical evaluations. It should be noted that any associated main reinforcement investments are still subject to the binary screening and technical evaluation process.

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[58] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 47
[59] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 48
[60] EB-2020-0091 Decision and Order, Integrated Resource Planning Proposal, July 22, 2021, p. 49
[61] EB-2024-0233 Correspondence, OEB Filing Requirements LTC Exemption Applications
[62] EB-2020-0091 Integrated Resource Planning Proposal, Decision and Order July 21, 2021, p. 44.
[63] EB-2020-0091 Integrated Resource Planning Proposal, Decision and Order July 21, 2021, p. 48.
[64] EB-2022-0200 Exhibit 2, Tab 6, Schedule 2, p. 282

Technical Screening and Evaluation

As per the OEB Decision, system needs progressing past the IRP binary screening will proceed through to a technical evaluation. The technical stage of the IRP Assessment Process is comprised of two components: technical screening and technical evaluation. This stage is intended to assess the technical viability of IRPAs to eliminate, reduce or defer the project scope.

As Enbridge Gas progressed to the Technical Evaluation stage of the IRP framework, it became evident that that not all investments passing Binary Screening required a detailed technical evaluation due to the nature of the project scope. A detailed technical evaluation involves network modelling of customer demands, demand reductions and/or incremental supply required to meet system needs. This is a rigorous and time-intensive process that would not be applicable to investment categories outlined in Table 1 below.

To reflect this distinction, the "Technical Evaluation" stage within the IRP Assessment Process has been updated to "Technical Screening and Evaluation," as shown in Figure 1. Enbridge Gas has discussed and reviewed the Technical Screening and Evaluation Process with the TWG, incorporated the feedback received and will continue to engage with the TWG to support ongoing refinement of the IRP Assessment Process.

Enbridge Gas has undertaken detailed technical project review of these investments, including initial verification of the forecasted need(s), project cost(s) and project driver(s). Through this process, certain categories and investment types were identified in which IRPAs would not be considered effective. The categories and rationale are described below and in Table 1. These investments are systematically screened out during the initial IRP technical screening process and these categories will be refined and updated to reflect any changes in the screening and evaluation process.

Concurrently, in 2023, the Enhanced Distribution Integrity Management Program ("EDIMP") was approved and established. As EDIMP pipelines undergo review and assessment, there may be changes to the scope and timing of the projects currently listed in the AMP, which in turn could affect the subsequent IRP analysis. These projects will be reviewed closely to ensure technical evaluation is completed on the updated scope.

Technical Screening

As noted above, Enbridge Gas identified categories of investments that do not have a technically feasible IRPA and subsequently screened them out at the technical screening stage. The categories of projects, their corresponding technical screening commentary and rationale are listed below.

Compressor Stations

- Technical Screening Comment: *Compression Station related projects are required to maintain existing capacity, deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions.*

The investments in the compression stations asset class related to the maintenance of the existing fleet of compressors include the periodic original equipment manufacturer ("OEM") prescribed overhauls and replacement of components that are not performing as intended or are obsolete. These types of investments cannot be offset by IRPAs and therefore will be screened out during technical screening. However, any investments driven by growth would be subject to the detailed technical evaluation process.

Hydrogen Blending

- Technical Screening Comment: *Hydrogen related projects are required as no IRPAs can replace the hydrogen feasibility assessments and hydrogen blending initiatives.*

The investments in the hydrogen blending asset class/program are related to the use of hydrogen in the distribution system, studies on hydrogen blending and are focused on reducing the carbon footprint of the existing transmission and distribution system. These investments cannot be offset by IRPAs and therefore will be screened out during technical screening.

Storage Pools & Wells

- Technical Screening Comment: "*Storage Pools & Well related projects are required to maintain existing capacity, deliverability and throughput. This is necessary to maintain security of supply and stable natural gas pricing during supply disruptions."*

The investments in the storage pools and wells asset class are related to maintenance and compliance driven upgrades to allow for ongoing deliverability from the storage pools. This includes the drilling of observation wells for compliance reasons and work that arises annually from the Integrity Management Program. These investments cannot be offset by IRPAs and therefore will be screened out during technical screening.

Distribution Stations

- Technical Screening Comment: *Distribution Station condition related, IRPAs not applicable*

The investments in this category are related to distribution station projects driven by the condition and not by growth. These distribution station condition related projects are prioritized based on inspections that evaluate the condition of various components (regulators, valves, piping, etc.) and systems (heating, odourant, communications, etc.) at the stations. In some instances, the specific projects are time constrained and low in dollar value and would fail at the binary screening stage. For larger projects, an understanding of the impact on upstream and downstream facilities is required and "like for like" replacement is usually preferable – particularly if a full station replacement is not being planned. As such, all condition related station rebuilds, and replacements will be screened out during technical screening. However, any station investments that involve an element of growth would be subject to the detailed technical evaluation process.

CNG Facilities

- Technical Screening Comment: *See investment description – IRPAs not applicable for CNG*

These investments are related to the ongoing replacement and upgrade of CNG facilities to fuel Enbridge Gas's natural gas vehicles. These needs cannot be replaced through IRPAs, and therefore will be screened out during the technical screening.

Other

- Technical Screening Comment: *See investment description, IRPAs not applicable*

The investments in this category were determined that there would not be a technically feasible IRPA and are described below in Table 1.

Project Status/ Timing Related

Technical Screening Comments:

- *A Leave to construct regulatory process has received OEB decision for approval of proposed project scope.*
- *LTC regulatory process in progress*
- *N/A - Project in construction phase*
- *N/A - Investment Cancelled*
- *N/A - Project Completed*

Investments that fall within this category are those that are already under construction, already granted leave to construct by the OEB or are projects that have been cancelled. These investments will be screened out during technical screening.

Table 1 – Description of Investments Screened out at the IRP Technical Screening Stage

	Sub-category	Asset Class	Asset Program	Description
1	AMI Pilot	Utilization	UTIL-Monitoring Systems	The AMI Pilot will establish the technical and economic benefits related to the installation of AMI meters and associated infrastructure. No technically feasible IRPA's can replace this spend.
2	AMP Fitting	Distribution Pipe	DP-Service Relay	An AMP fitting is a mechanical fitting installed between 1969 and 1984, on below ground residential gas service lines, to transition from a plastic service line to a copper riser. Locations with an AMP Fitting are identified annually and prioritized based on risk.
3	Class Location	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Class Location TPUS-Class Location	This is one of the Integrity Management Programs in which the spend is held in a Programmatic spend budget to cover specific projects that are identified each year. Class locations projects arise when a facility needs to be relocated because of increased development and associated population density around the facility. The programmatic spend cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
4	Compression Stations	Compression Stations	All	See section above on Compression Stations
5	Corrosion	Distribution Pipe	DP-Corrosion	This programmatic spend covers the replacement of depleted anodes, work arising from bridge crossing inspections, and repairs to rectifier beds.
6	Depth of Cover Program	Transmission Pipe & Underground Storage	TPUS-Integrity	This programmatic spend budget is for facilities that are identified each year as exposed or shallow leading to an increased risk of 3rd party damage. Once identified the pipeline must be lowered, replaced, or otherwise protected to control risk. The programmatic budgeted here cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
7	District Station	Distribution Stations	DS-Station Rebuilds & B & C Stations	These investments hold budget for specific station rebuild investments that have been identified through annual inspections and that have been prioritized for rebuild based on condition.
8	Farm Taps	Utilization	UTIL-Regulator Refit	This is programmatic spend that is budgeted to cover the costs of remediating situations in which there are problems with the first or second cut of the regulation at a customer's premise.

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9	Facilities Integrity Management Program (FIMP)	Distribution Stations	DS-Integrity	This is programmatic spend that is budgeted to cover the costs of large station inspections that must be completed annually to scope the extent of work that is required at each large station investment identified in the AMP. The programmatic spend cannot be assessed for IRPAs, however, any identified facility replacements where growth is a project driver will be included in the IRP Technical Evaluation
10	Fire Suppression	Distribution Stations	DS-Gate, Feeder & A Stations	These investments relate to the installation of Fire Suppression at Distribution Stations with Odourant. Going forward all such Station programs that are driven by condition, end-of-life, and compliance will be removed from IRP Technical Evaluation.
11	Geohazard	Distribution Pipe	DP-Integrity	This integrity management programmatic spend is budgeted to cover the costs related to identifying pipelines that must be replaced because of risks related to geohazards. The programmatic spend cannot be assessed for IRPAs, however, any resulting pipeline replacements will be included in the IRP Technical Evaluation.
12	Independent Asset Integrity Review (IAIR)	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Integrity, TPUS-Integrity	This is programmatic spend that is budgeted for work that results from the Independent Asset Integrity Review. The programmatic spend budgeted cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
13	Integrity Digs	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Integrity, TPUS-Integrity	This programmatic spend is budgeted to cover the costs related to repairs and replacements that are identified through in-line inspections. The programmatic spend cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation
14	Integrity Retrofit	Distribution Pipe, Distribution Stations & Transmission Pipe & Underground Storage	DP-Integrity, DS-Integrity, TPUS-Integrity	This is programmatic spend that is budgeted for installing pig launchers and receivers, allowing annual in-line inspection to be accomplished more easily and the life of transmission pipelines to be potentially extended. This work takes place at stations and does not affect the distribution system itself.
15	Inside Room Regulators (IRR)	Distribution Stations	DS-Inside Regulator & ERR Program	This is programmatic spend that is budgeted for remediation of inside regulation sets based on risk.

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16	Large stations	Distribution Stations	DS-Gate, Feeder & A Stations	These stations are identified through inspections and prioritized for rebuild based on condition. Each year, this programmatic spend is converted into specific projects. Any identified investments where growth is a project driver will be included in the IRP Technical Evaluation. It should be noted that there is also the possibility that reduced load will drive some investment in stations.
17	Liquified Natural Gas (LNG)	LNG	All	These investments relate to the maintenance of the Hagar LNG facility that is used to peak shave the load in the Sudbury area. Unless driven by Growth, all investments at the Hagar facility will be excluded from the Technical Evaluation moving forward.
18	Low Pressure Delivery Meter Sets (LPDMS)	Utilization	UTIL-Remediation	This is programmatic spend budgeted to cover the inspection and remediation of Low-Pressure Delivery Meter sets, which are usually at commercial customer locations.
19	Main & Service Repl - Leaking	Distribution Pipe	DP-Service Relay	Similar investments in the EGD Rate Zone were excluded at Binary Screening and going forward these too will be excluded at Binary Screening as Emergent Safety Issue. Aside from the safety concern, leaks must be addressed quickly to avoid GHG's.
20	Meter exchanges	Utilization	UTIL-Regulator Refit	This programmatic spend is budgeted to cover the costs of replacing meters through the Measurement Canada approved processes.
21	Maximum Operating Pressure (MOP) Verification	Distribution Pipe & Transmission Pipe & Underground Storage	DP-Replacements, TPUS-Replacements	This programmatic spend is budgeted to cover the replacement of pipelines where this may be required because of a review of records for pipeline systems operating above 30 per cent SMYS. Once the MOP has been identified and based on the associated risk, the pressure in these pipelines may need to be reduced until the pipeline can be replaced. The programmatic spend cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
22	Odourant Program	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for the upgrade of odourant systems at stations.
23	Pressure Factoring Metering (PFM) Program	Stations	DS-Station Rebuilds & B and C Stations	This programmatic spend is budgeted to cover the costs of PFM stations that require a bypass.
25	Relocation Program	Distribution Pipe	DP-Relocations	This programmatic spend has been budgeted to cover the costs of projects that are identified annually in response to the requirements of municipalities and other agencies. The programmatic spend cannot

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				be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation
26	Remote Terminal Units (RTU)	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for the replacement of Remote Terminal Units that are no longer supported by the manufacturer.
27	Storage Facility	Transmission Pipe & Underground Storage	TPUS-Improvements	As noted above, investments related to Storage Pools and Wells will be excluded from Technical Evaluation going forward unless they are driven by growth.
28	Telemetry	Distribution Stations	DS-Gate, Feeder & A Stations	These investments are for telemetry at distribution stations.
29	Vintage Steel Main (VSM)	Distribution Pipe	DP-Replacement	There is a programmatic spend budgeted for Vintage Steel Main projects that have not yet been identified. The programmatic spend cannot be assessed for IRPAs, however, any identified pipeline replacements will be included in the IRP Technical Evaluation.
30	Well Laterals	Transmission Pipe & Underground Storage	TPUS-Integrity	As noted above, investments in Storage Pools & Wells, and their associated Integrity Management Programs will be similarly excluded from Technical Evaluation.

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Technical Evaluation

Investments that are not screened out through the technical screening, as noted above, proceed to a technical evaluation. Examples of the technical evaluation form can be found at EB-2022-0200, JT 5.36 Attachment 3 and 4.

During the technical evaluation, Enbridge Gas assesses the technical feasibility of the following IRP alternatives (IRPAs):

- Supply-side alternatives:
  - Compressed Natural Gas ("CNG"): Consideration of CNG injection volumes, the number of years of CNG, location of CNG injection, and the subsequent impact to project scope
  - Market-based supply: Consideration of the presence of a third-party source in the project area-of-benefit, the availability of higher pressure or increased capacity, and the subsequent impact to project scope
- Demand-side alternatives:
  - Enhanced Targeted Energy Efficiency ("ETEE"): Consideration of the level of peak demand reduction required, the level of peak demand achieved by ETEE, the number of years of ETEE, the amount of firm contracted demand on the system and potential reduction, and the subsequent impact to the project scope.
  - Demand Response ("DR"): Consideration of the level of peak demand that can be shifted through DR, and the subsequent impact to the project scope

The following are the types of technical evaluation commentary associated with investments with technically feasible IRPAs.

IRPA(s) applicable – IRPA(s) applicable could defer, reduce or eliminate project scope

These investments pass the technical evaluation as there are technically feasible supply or demand side IRPA(s) that could impact the project scope. These investments proceed with detailed system modelling for peak hour demands.

The following are the types of technical evaluation commentary associated with investments with no technical feasible IRPAs. These investments will be excluded from further detailed technical evaluation.

Scope is NPS 2, cannot downsize further or retire

The existing scope is already NPS 2 and thus cannot be further downsized. These investments were then reviewed to determine whether they could be retired. These scopes had services coming off the pipe that needed to be maintained and thus cannot be retired. Since the pipe size cannot be reduced beyond NPS 2 and cannot be eliminated, IRP has no impact on the project scope and therefore fails technical evaluation.

Potential to be downsized to NPS 2. Further assessment closer to ISD

During technical evaluation, it was determined that the project scope could potentially be replaced with NPS 2 prior to any IRP assessment. If the pipe size can be reduced, then IRP will not be applicable; the scope will be confirmed when the project enters the detailed design phase.

Timing – Market Based Supply Side not available

Some investments failed because they are required in the near term (1-3 years) and there is no technically feasible supply-side alternative that can meet the need.

Economic Evaluation

Investments that pass the technical evaluation proceed to the economic evaluation stage, where a three-phase DCF+ test is conducted to assess the cost effectiveness of IRP and facility alternatives. While there is a strong emphasis on the rate impact from the DCF+ Phase 1 test, additional factors are taken into consideration to determine the selection of the optimal alternative.

The key considerations to assess cost effectiveness includes:

- Phase 1 NPV results from the DCF+ (Relative Rate Perspective)
  - The Phase 1 DCF+ calculates the benefits and costs for existing ratepayers and reflects the utility perspective by assessing the impact on future utility rates

  Phase 1 + 2 NPV results from DCF+ (Total Customer Perspective)
  - The combined Phase 1 and Phase 2 DCF+ results reflect the total Enbridge Gas customer perspective, by assessing the impact to existing ratepayers and participants, reflecting the entire customer base's economic impacts.

- Combined Project Capital and O&M Cost
  - Alternatives are compared to determine the lowest cost alternative based on the combined project capital and O&M costs and the lowest relative bill impact.

- Persistence of Demand
  - The underlying demand profile driving the capacity constraint is reviewed to ensure the most cost-effective alternative is aligned with project needs. The demand forecast profiles typically fall within the following patterns:
    - Demand is forecast to continue increasing over the period
    - Demand is forecast to increase in the short term and then decline
    - Demand is forecast to increase in the short term and then stabilize

Enbridge Gas determines the preferred alternative by selecting the option with the highest Phase 1 NPV. This preferred alternative is further validated by comparing it with the combined Phase 1 + Phase 2 NPV results. In Enbridge Gas' experience, the preferred alternative is consistently supported by both Phase 1 and Phase 1 + Phase 2 results.

To inform decision thresholds and test robustness, single-variable cost sensitivity analyses on O&M and capital expenditures will be conducted. These analyses will determine the cost shift required for the other alternatives to achieve parity on Phase 1 NPV with the preferred alternative.

The final selection of the optimal alternative reflects a balance of considerations, including Phase 1 NPV results supplemented by consideration of the Phase 1+2 NPV results, the cost-effectiveness differential between alternatives, the forecasted demand profile, total project costs, relative customer bill impacts, while also taking into account the single-variable cost sensitivity analysis.

Following this determination, investments for which an IRP alternative is identified as the optimal solution will advance to the IRP Plan development[65] or implementation stage, or continue to be monitored and reviewed annually to confirm the IRP alternative remains the optimal solution, based on their respective lead times. Conversely, investments for which a facility alternative is deemed optimal will either proceed with the implementation of the facility alternative or continue to be monitored and reviewed annually to confirm the facility alternative remains the optimal solution.

[65] IRP Plan filing with OEB is only applicable for investments greater than $2M.

Appendix G: SLH Evaluation, Measurement and Verification Plan



Evaluation, Measurement, and Verification Plan

Southern Lake Huron (SLH) Integrated Resource Planning (IRP) Pilot

Prepared for:

Enbridge Inc.

April 2026

dunsky Energy + Climate

Submitted to:



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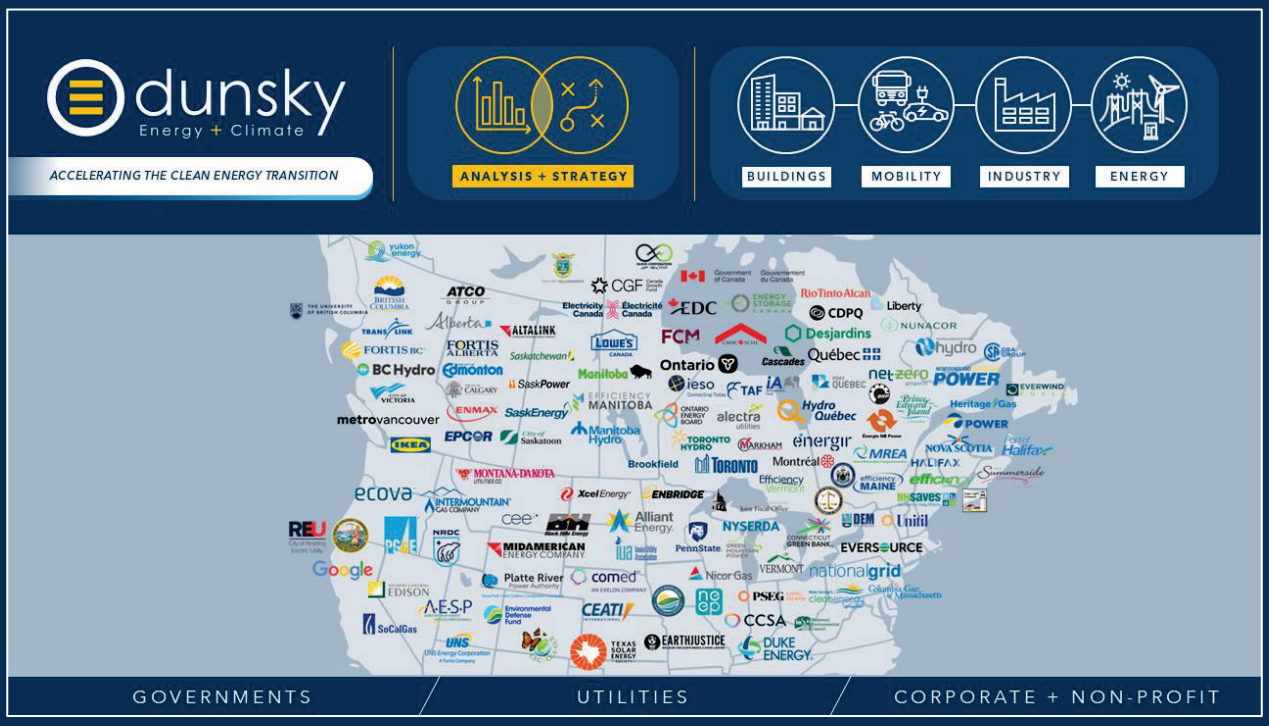
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About Dunsky



Dunsky supports leading governments, utilities, corporations and others across North America in their efforts to accelerate **the clean energy transition**, effectively and responsibly.

With deep expertise across the Buildings, Mobility, Industry and Energy sectors, we support our clients in two ways: through rigorous **Analysis** (of technical, economic and market opportunities) and by designing or assessing **Strategies** (plans, programs and policies) to achieve success.



Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax. Visit dunsky.com for more information.

Executive Summary

The Southern Lake Huron (SLH) Integrated Resource Planning (IRP) Pilot is Enbridge Gas' first large-scale effort to measure whether demand-side Integrated Resource Planning Alternatives (IRPAs), specifically Enhanced Targeted Energy Efficiency (ETEE) and Demand Response (DR), can provide significant measurable reductions in peak hour natural gas demand and support system planning under the OEB's IRP Framework. With approximately 30,000 customers across a representative mix of residential, commercial, and industrial segments, the SLH region provides a strong test case for evaluating these alternatives.

This Evaluation, Measurement, and Verification (EM&V) Plan outlines the methods, data sources, analytical procedures, and reporting structure that will guide the independent evaluation of the SLH IRP Pilot. Developed to fulfill the OEB's direction and Enbridge's IRP Pilot commitments, the EM&V Plan provides a transparent, rigorous, and replicable framework to determine the extent to which ETEE and DR measures can reduce peak hour loads and contribute to system reliability under design-day conditions.

Evaluation Objectives

The evaluation focuses on enabling Enbridge to develop a clear understanding of how ETEE and DR programs impact system peak hour demand. Specifically, the evaluation will:

- Quantify actual peak-hour flow reductions (m^3/h) from ETEE and DR by comparing pre- and post-program load.
- Assess DR event performance, including the reliability, magnitude, and persistence of customer response.
- Identify factors that influence achieved impacts (weather, building characteristics, measure types).
- Extrapolate observed impacts to design-hour conditions using Enbridge's regression methods.

These findings will support future IRP Plans by improving assumptions, refining modeling techniques, and informing the feasibility of using demand-side IRPAs in lieu of traditional system reinforcement projects.

Evaluation Methodology

The evaluation applies a set of coordinated analytical approaches to estimate program impacts.

- Load-vs-temperature regression to measure normalized pre/post load changes and validate Enbridge's regression approach.
- Participant vs non-participant comparisons using hourly interval meter data.
- DR event analysis using smart thermostat telemetry matched to consumption records.
- Impact disaggregation by customer type and measure where statistically reliable.
- Load curve analysis to examine peak shifting, rebound effects, and system-level peak relief.

As part of this approach, customer demand extrapolation will be led by Enbridge, with Dunsky providing methodological review and collaboration. This collaborative approach enables the evaluation to leverage Enbridge's deep expertise in system design, demand

profiling, and historic Ontario design-day practice, while also incorporating Dunsky's experience in demand response, regression-based load modeling, and large dataset evaluation.

All analyses will incorporate rigorous data validation and transparency regarding uncertainty levels, underlying assumptions, and extrapolation techniques. The evaluation relies on hourly meter data, weather data (temperature, wind), smart thermostat event records, and program tracking datasets.

Evaluation Timeline and Deliverables

The evaluation is structured across two heating seasons. Key deliverables include:

- **Draft EM&V Plan** – January 2026.
- **Final EM&V Plan** – March 2026.
- **Interim Report** – Q3 2026, based on the first full winter of data and initial impact results.
- **Final Evaluation Report** – mid-2027, integrating both years of results and full system-level analysis.

Ongoing data requests, regression quality assurance, and periodic updates to Enbridge staff will ensure continuous alignment throughout the evaluation process.

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1. Pilot Background

Enbridge Inc. (Enbridge) has developed and is implementing an Integrated Resource Plan (IRP) pilot in the Southern Lake Huron (SLH) region to evaluate the impact of Integrated Resource Planning Alternatives (IRPA) on the local system peak hour. An IRPA is a potential solution other than a Facility Alternative considered in Enbridge Gas' IRP Assessment Process in response to a specific system need of Enbridge Gas[1].

investments or activities that provide utilities with an opportunity to reduce system costs, emissions, and customer risk by offering cost effective alternatives to infrastructure investment.

In July 2021, the Ontario Energy Board (OEB) issued the first Integrated Resource Planning (IRP) Framework to shape the process to compare and evaluate IRP alternatives for natural gas system needs. The Framework prescribes that IRPAs must be in the best interest of Enbridge Gas and its customers; thus, any alternative must align with the guiding principles of reliability, safety, cost-effectiveness, public policy, optimized scoping, and risk management.

The OEB has since provided approval for the SLH IRP Pilot Project, which Enbridge is implementing to understand and evaluate how IRPAs can potentially avoid, delay, or reduce facility projects.

As outlined in the pilot application to the OEB, the primary objectives of the SLH IRP Pilot project are twofold.

1. Develop an understanding of how Enhanced Targeted Energy Efficiency (ETEE), Demand Response (DR) programs, electrification measures, and advanced technologies impact peak hour flow/demand.
    a. Quantify actual peak hour flow reductions (m3/hr) resulting from ETEE and DR programming by customer type by comparing peak hour flow per customer prior to and after ETEE and DR programming is implemented.
    b. Evaluate DR event parameters on peak hour flow reductions and the adoption and persistence of customer participation in DR programming over time.
2. Evaluate and understand how to design, deploy, and evaluate ETEE and, residential DR programs, as well as other IRPA measures, that are targeted to specific, geographic areas.

The scope of this project is to support the achievement of objective 1. Outputs from this evaluation may serve as the input to future projects or initiatives.

The SLH distribution system supplies natural gas to approximately 30,000 customers located in the City of Sarnia and the Village of Point Edward in the County of Lambton. The market characteristics match well to Ontario as a whole, with a balanced mix of residential, commercial and industrial customers.

[1] IRP Framework for Enbridge Gas, July 22, 2021. pp 4.

Figure 1 - SLH Pilot Area



The SLH IRP Pilot operates within the same planning framework used to determine Enbridge Gas's system capacity requirements. Under the *Design Criteria and Design Demands Process* (EB-2022-0200), Enbridge defines system design criteria using the coldest observed day on record, expressed as Heating Degree Days adjusted for wind speed (HDDw). This "set-temperature" method reflects a no-failure reliability standard - ensuring that all infrastructure and operational plans can meet customer demand during the coldest historical conditions. The associated design-day (maximum daily) and design-hour (maximum hourly) demands form the basis for system sizing, reinforcement decisions, and assessment of Integrated Resource Planning Alternatives (IRPAs).

By evaluating how Enhanced Targeted Energy Efficiency (ETEE) and Demand Response (DR) affect peak-hour load under these design conditions, the pilot provides empirical evidence on whether demand-side resources can offset or defer capital investment while maintaining Enbridge's mandated reliability and safety standards.

The pilot focuses on residential and commercial programs, including[2]:

- enhanced residential whole home and single measure demand-side management (DSM).
- enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM.
- electrification measures (ASHP, GSHP) with limited residential customer participation, including customers who have previously installed these, where known.
- residential demand response (DR) pilot, using a bring your own device (BYOD) strategy to target gas space heating.

Roughly 1600 participants are expected for residential ETEE pilot offers, 700 participants for residential DR, and 60 to 150 participants for Commercial ETEE Pilot Offers.

Enbridge has engaged Dunsky Energy + Climate Advisors (Dunsky) to evaluate its Southern Lake Huron (SLH) Integrated Resource Planning (IRP) pilot project. This evaluation plan document outlines and is intended to guide the evaluation process. It is a crucial first step to understand the SLH IRP pilot and surrounding factors, outline evaluation objectives, identify appropriate data and data sources, and describe the evaluation methods and schedule to

[2] Advanced technology measures have not yet been approved in the OEB Decision and Order, but are at issue in the OEB Motion to Review.

meet Enbridge's evaluation obligations as determined by the OEB. This document includes an overview of the SLH IRP pilot program, supported projects, evaluation objectives, key research questions, methodology, evaluation schedule, and how findings will be communicated.

2. Key Research Objectives

The objective of this work is to support Enbridge's pursuit of the first IRP Pilot Project objective in developing an understanding of how ETEE and DR offerings impact peak hour flow/demand throughout the duration of the IRP Pilot Project term through evaluation activities. The evaluation of this objective will assist Enbridge in the refinement of the approach and assumptions to be applied to the evaluation and implementation of these programs in relation to the IRP process and future IRP Plans.

Specifically, the evaluation aims to:

- Quantify actual peak hour flow reductions (m3/hr) resulting from ETEE and DR programming by customer type by comparing peak hour flow per customer prior to and after ETEE and DR programming is implemented.
- Evaluate DR event parameters on peak hour flow reductions and the adoption and persistence of customer participation in DR programming over time.
- Extrapolate evaluation findings to project design peak impacts using Enbridge's regression analysis approach.

3. Data Sources

3.1 ERT Data

3.1.1 ERT Data Description and Scope

ERT (Encoder Receiver Transmitter) data are hourly gas consumption readings collected from Enbridge's smart gas meters. These meters transmit interval data, providing time-stamped hourly usage records that can be used to assess load shape, seasonal patterns, and customer responses to demand-side measures.

In the SLH IRP Pilot, ERT data are the primary quantitative input for evaluating peak-hour demand impacts of Enhanced Targeted Energy Efficiency (ETEE) and Demand Response (DR) programs. The data allow for direct comparison of pre- and post-program peak usage (m^3/h) by customer type and region. The following table shows ERT customer counts for available hourly data in the SLH pilot region as of early 2025.

Customer Type	Hourly ERT Data	Total	% with Hourly ERT Data
Residential	18,976	26,597	71%
Commercial/ Industrial	1,505	2,170	69%
All Customers	20,481	28,767	71%

3.1.2 ERT Data Quality and Challenges

Review of hourly data has highlighted some gaps and challenges on some routes. ERT data quality is influenced by meter age, route configuration, and data transmission settings.

- **Completeness:** Vintage ERTs (prior to 2009) are not able to provide hourly data (represents approximately 30% of all customers). For the ERTs that are able to provide hourly data, over 70% of meters have been gathering data consistently (50% of total customers). Gaps are being closed through updated meter-reading contractor procedures that ensure hourly data collection is enabled for ERTs. It is expected that additional customers with ERTs will have adequate baseline hourly data prior to customer measures being implemented.
- **Temporal Alignment:** Each route's data are time-stamped and linked to corresponding hourly weather (temperature, wind) data for regression analysis by Enbridge. Multiple weather stations will be considered and analysed.
- **Spatial Coverage:** Routes in both urban Sarnia and Point Edward are read monthly, ensuring regular geographic sampling across mixed customer types. Intermittent route gaps and errors remain a variable that will need to be managed through ongoing data quality processes.
- **Data Validation:** Enbridge performs load-vs-weather regression analysis and is developing automated processes to handle the hundreds of millions of hourly ERT data points. Dunsky will be validating and replicating the processes and analysis in samples of data.

3.2 BrightLync Data

3.2.1 BrightLync Data Description and Scope

BrightLync modules are advanced telemetry devices installed on commercial and industrial (C/I) meters to record and transmit hourly natural gas consumption data. The technology is appropriate for the larger meter sizes these customers sometimes use.

In 2024-Q4, Enbridge reached out to large C/I customers in the SLH pilot area; over 90 customers showed interest in meter station upgrades, and Enbridge proceeded to order BrightLync modules. Meter station upgrades (swap or rebuild) are sometimes challenging, involving product procurement, scheduling, customer availability, and technical needs (e.g. bypass availability for duration of work, location of meter, etc.).

At the end of 2025, approximately 80 BrightLync devices will be installed, as well as hourly ERTs on smaller commercial sites interested in the SLH pilot. Additional devices will be installed on a customer interest basis from the program roll-out. Baseline data gathering begins with installation and proceeds until a customer implements an ETEE measure.

3.2.2 BrightLync Data Quality and Challenges

BrightLync installations deliver high-resolution, equipment-calibrated readings suitable for regression analysis ETEE measure impact verification, but several operational and data-integrity challenges remain.

- **Installation Constraints:** Winter conditions limit work at sites without bypass valves, delaying some installations until warmer weather. Meter swaps and rebuilds depend on customer availability and coordination with internal station crews, introducing variability in data start dates.
- **Baseline Duration:** Because BrightLync module installation began in early 2025, only limited pre-program data (one heating season or less) may be available before ETEE implementation begins.
- **Data Integration:** Enbridge is still integrating BrightLync feeds into its central hourly meter database to enable automated analytics.
- **Data Completeness:** Early datasets cover only a handful of customers; broader rollout through 2025 is ongoing to achieve statistically meaningful samples.
- **Measurement Verification:** Ongoing data-quality and calibration reviews are in place to ensure reliable readings as additional modules come online.

3.3 Weather Data

3.3.1 Weather Data Description and Scope

Weather data are used to assess gas consumption and load sensitivity to outdoor temperature and wind. In the SLH pilot area, Enbridge currently uses hourly temperature and wind data from regional Environment and Climate Change Canada (ECCC) weather stations near Sarnia and the Southern Lake Huron service area (London, Windsor), synchronized to hourly gas meter readings.

This data is used by Enbridge teams as part of their load-vs-weather regression models, which quantify how natural gas demand varies with weather (temperature and wind) and time of day for typical modeling activities.

Regression parameters derived from weather data (e.g., heating degree hours, temperature, wind) allow for comparison of participant and non-participant peak-hour demand, controlling for climatic variability.

For program evaluation purposes, weather data will be used to generate Heating Degree Hour (HDH) and wind-adjusted Heating Degree Day (HDDw) indicators, consistent with Enbridge's *Design Criteria and Design Demands* Process. The HDDw formulation accounts for the combined influence of temperature and wind speed on heating load and provides the linkage between the pilot's regression models and Enbridge's official design-day conditions. This will be applied in both baseline/non-participant normalization and participant impact models. Enbridge will also investigate the modeling accuracy results with different weather station locations (Windsor vs London). Other variables may be considered as described in 4.4.

3.3.2 Weather Data Quality and Challenges

While temperature data from ECCC and other public sources are generally reliable, several factors influence the quality and representativeness of weather inputs in the SLH pilot context.

- **Spatial Resolution:** The SLH region spans both urban and rural microclimates, and a single reference station (e.g., Sarnia Airport) may not perfectly reflect all local conditions, especially for coastal or industrial zones. This effect is likely to be minor or negligible and can be mitigated by using data from multiple nearby ECCC stations.
- **Temporal Alignment:** Precise timestamp synchronization between hourly temperature readings and ERT/BrightLync consumption records is required; even small-time offsets can introduce regression noise during peak-hour periods.
- **Missing or Noisy Data:** Occasional data gaps, rounding errors, or timestamp irregularities from ECCC feeds can reduce continuity in the hourly temperature series. These are typically corrected through interpolation or substitution from nearby stations. Depending on the type and volume of customer data or weather data that may be missing, Enbridge either removes the data for linear regression, or substitutes average customer sizes for day-to-day modeling. Substitution prior to regression is not completed since this is not for customer billing or any other purpose for monthly needs. For the SLH pilot, no substitution should take place on the upfront data gathering.

3.4 Smart Thermostat Data for Demand Response

3.4.1 Smart Thermostat Data Description and Scope

Smart thermostat data is a customer-level data source for evaluating Demand Response (DR) program performance. The data captures both thermostat operation and event participation metrics during scheduled DR events intended to reduce gas demand during system peak hours.

For participating residential customers, smart thermostats record:

- temperature setpoints (before, during, and after DR events).
- HVAC system runtime and cycling behaviour.
- event participation details (including opt-ins, opt-outs, and overrides).
- customer interaction data (such as manual adjustments during events or comfort complaints logged through apps).

This data is transmitted via the thermostat vendor's cloud-based platforms. Thermostat and consumption data must be linked before these records are anonymized and aggregated to provide useful inputs for integration into the DR evaluation dataset. Information will be anonymized between the DR Delivery Agent and Enbridge by using a unique customer identifier code rather than an account number, address, name, etc.

These datasets are used to quantify average hourly load reductions (m^3/h) during event windows relative to baseline hours (non-DR event hours during cold weather). It can also be used to assess event reliability, customer persistence, and rebound effects (post-event load increases). These data are paired with ERT hourly consumption data and weather variables to create complete regression-ready event records for impact analysis. In this analysis, ERT data

may be primary, with the vendor thermostat data providing details on customer opt-outs, quantities, etc.

3.4.2 Smart Thermostat Data Quality and Challenges

While smart thermostat telemetry provides rich, high-frequency behavioural data, several data quality and coverage challenges affect its use for rigorous DR impact evaluation:

- **Data Provision:** As of the date of issue of this EM&V Plan, there is a signed contract with a smart thermostat contractor for data provision, but discussion is ongoing regarding specific data and information to be provided. Exact details on provision and access to smart thermostat data will shape the extent to which DR measures can be evaluated.
- **Data Limitations:** Smart thermostats do not differentiate what equipment they control and only have runtime data. Thus, actual equipment consumption cannot be known from smart thermostat data alone.
- **Data Integration and Timing:** Smart thermostat event data and ERT gas consumption data are logged by separate systems, often at different timestamps or time zones. Aligning thermostat runtime data with hourly gas usage for the same household requires precise temporal synchronization to avoid misattribution of DR effects.
- **Limited Penetration:** Only a subset of ERT-equipped residential customers are expected to have enrolled in the DR program during the initial pilot window. This small sample size may limit statistical significance in aggregate DR savings estimates. This uptake will be determined during the course of the SLH pilot evaluation.
- **Opt-Outs and Overrides:** Customer comfort preferences may alter event outcomes. Opt-outs or manual adjustments during an event reduce measured savings and increase variability in results.
- **Temperature Rebound and Persistence Effects:** Post-event "catch-up" heating can create a new peak if mitigating strategies are not put in place. Detecting this requires multi-hour post-event tracking and accurate weather normalization. Depending on the number of enrolled customers and geographic locations, this post-event peak is likely acceptable if the overall system peak is reduced on the system of need. This may necessitate groupings of DR measures or limits on customer saturation of DR.

3.5 Other Data

3.5.1 Other Data Description and Scope

In addition to metered consumption and weather data, the SLH IRP Pilot draws on a suite of program-level, customer-level, and contextual datasets to support evaluation. These "other" data sources enable evaluators to understand who participated, what ETEE measures were installed, and DR event opt-in rates. Key datasets include the following.

- **Program Tracking Data:** Participation records from Enbridge's internal IRP and DSM systems, documenting customer enrollment dates, measure types (e.g., insulation, heat pumps, etc.), installation timelines, and incentive levels.
- **DSM / ETEE Program Records:** Legacy and pilot-specific DSM datasets identifying equipment characteristics, savings assumptions, and measure costs, used for cross-comparison with historical program performance.
- **Customer Characteristics:** Building type, age, size, heating system type; drawn from Enbridge's customer database and MPAC property records.

3.5.2 Other Data Quality and Challenges

While these datasets provide valuable context, they are administrative rather than instrumented data sources and thus carry their own limitations and consistency risks.

- **Data Completeness:** Program records may omit installation dates, or measure details.
- **Consistency Across Systems:** DSM, IRP, and customer information systems were developed separately; ensuring consistent identifiers (e.g., customer account number, premise ID) across systems is essential for clean joins with metered data.
- **Timeliness:** Updates to participation and installation records can lag behind actual implementation, creating potential misalignment between "program start date" and observed load impacts.
- **Data Accuracy:** Building and demographic data (e.g., MPAC) can contain outdated information on building size or system type, requiring validation against billing or field data.
- **Administrative Limitations:** MPAC data carries contractual limitations on storage, adding complications to data handling practices; accessibility of this data to be explored during evaluation activities.

4. Customer Load Extrapolation Methodology

4.1 Overview

The customer demand extrapolation will be led by Enbridge with collaboration from and methodology evaluation by Dunsky. This will allow the pilot results to draw on the expertise of Enbridge in system design, demand profiling, and historic design practice in Ontario, while allowing for Dunsky's experience in demand response, regression-based load modeling, and large dataset evaluation to be incorporated. In addition to validating the methodology and general evaluation approach, Dunsky will run analyses on data samples to verify the peak impact estimates.

This section contains an overview of Enbridge's proposed load extrapolation methodology and approach, which is under review by Dunsky as described in Section 5 of this EM&V Plan document. It is intended to contextualise the peak design methodology used by Enbridge and the pilot project, but does not constitute an evaluation methodology for the pilot project (the evaluation methodology for the pilot project is described in Section 5 and subsequent sections). This pilot project focuses on using actual consumption data to understand customer consumption patterns for the purposes of gas delivery network design. However, since these networks are designed to meet demand under extreme weather conditions it is important to estimate consumption at these conditions. The extreme weather condition is termed the Design Degree Day. Extrapolations must be used since these extreme weather conditions are infrequent, and have a low probability of occurrence during the 2-year pilot timeframe.

Several models will be developed to extrapolate the actual data to design conditions. Models will focus on isolating demand data for a specific time period (ex. demand on Wednesday at 7 AM during the winter) and assessing the sensitivity of demand against hourly weather data. This allows for linear regressions to be performed for each time period separately.

Statistical analysis will be performed to understand the strengths and weaknesses of the different models for different groups of customers. The Root Mean Square Error (RMSE) will be calculated to evaluate the strength of the various models. When comparing models a higher weight is given to model performance during the highest consumption hours, cold months, and extreme cold temperatures to bias the results towards accuracy under these conditions. The best performing model for the majority of customer demand will be selected by Enbridge to estimate design customer demand.

Coincident peak of all customers is considered to ensure results are appropriate for system design. The customer models will be combined into a system profile to determine when the coincident peak occurs at a Design Degree Day. Once the time of the coincident peak is determined the demand from each customer at this time will be considered their peak demand for system design. Once developed these models can be used on consumption history for different time periods to understand how ETEE and DR impact customer peak demand.

4.2 Data Validation and Filtering

Prior to regression modeling, all input datasets undergo systematic data validation and cleaning to ensure reliability and comparability. Where either consumption or weather data is missing the data is removed. Missing weather data is an infrequent occurrence, so estimating gaps is unnecessary. While in some cases there are substantial gaps in consumption data, the gaps are very long so filling them in would pose a large challenge. Additionally, since the model is meant to predict consumption (not estimate billing), this would create a feedback loop where estimates are used to model more estimates which would undermine the validity of the results.

Holidays and days where local time shifts due to DST adjustments will also be filtered out since habits during these days may be affected. The period from Christmas to New Years is also removed since many businesses shut down during this time frame, which could affect not only their demand, but residential demand since the workers schedules will also be affected.

Only winter data will be used for creating models to bias the results to cold temperatures during the heating season. Winter is defined as December through March inclusive. While shoulder seasons (spring and fall) could be utilized in regression, it can be difficult to predict if a customer's heating system is active, which can lead to difficulties in predicting consumption. Removing the shoulder seasons from the analysis eliminates this variable.

Interquartile analysis is performed on each customer's demand to detect outliers. The analysis must incorporate temperature since its exclusion can make it seem like customer demand at extreme temperatures are outliers, which would remove some of the most critical data.

4.3 Linear Regression by Hour

Data will be separated by hour such that 24 individual linear regressions can be performed. Customer consumption is regressed against heating degree hours. This allows for the heat sensitivity of customers to be understood while isolating for differing habits across the day. The constant variable from the regression represents the base demand present under all weather conditions for uses like water heating, cooking and process loads. The slope represents the temperature sensitivity of the customer per degree hour representing building heating.

Inputting a degree hour into 24 equations will yield a customer demand profile for the day. Demand surfaces can also be created by combining the profiles for all possible degree hours into a 3D graph.

4.4 Model Variations

Different versions of the model will be developed to ensure that system demand can be estimated as accurately as possible. Permutations of variations will be evaluated against each other to assess which is the most appropriate. Below is a preliminary list of variations that are expected to be tested.

Base Temperature

Enbridge uses a constant base temperature of 15°C when calculating degree days. While this is a standard average base temperature, it may not be appropriate for all customers. Additionally, due to variables such as building occupancy and thermostat setbacks, this value

may not be appropriate for a single customer under different time periods. Models will be developed allowing variation of base temperature between customers and times.

Recent Weather History

Buildings have thermal mass that may not react instantly to changes in outdoor temperatures. Models will be developed to determine whether averaging temperatures in recent hours reduces model error. Degree days will be compared with degree hours with and without wind speed adjustments. Alternate models with lagged variables will be explored.

Weekday Effects

Different days of the week will have different customer habits affecting consumption. Ideally models would seek to look at these effects independently, but this will limit the amount of data available for each regression. It will be investigated if there are significant differences between different days of the week, and if sufficient data is available to improve model performance.

4.5 Demand Response Analysis

Analyzing demand response (DR) events will be challenging since there will be fewer days of data that can be evaluated than for ETEE. This will be mitigated by intentionally selecting event days with a range of outdoor temperatures at which to observe trends.

DR analysis will use the same regression methodology as outlined in herein for ETEE but will only have event days included in the analysis to understand customer demand during events. Non-DR event days will be used to estimate what the demand likely would have been to measure against (expanded upon in Section 8).

4.6 Model Validation Approach

Since multiple analysis models will be developed, it is important to have a repeatable method of validating modeled results. The following methods will be used to ensure modeled results are appropriate for system design.

Segmenting Model Training and Test Data

Since multiple models will be developed there is a risk of overfitting models. This could occur if the selected model performs well on the historical meter reads collected, but when new meter reads are gathered the model performance drops. This could be due to some coincidental factor in the historical data that might not be present in future data.

To mitigate the chance of overfitting, data will be split into training data and test data. Training data will be used as an input to models linking external weather data with consumption patterns. Once the models are developed for all customers, the test data will be used to calculate composite RMSE values for evaluating model performance.

Composite RMSE

The primary statistic used for this evaluation will be the Root Mean Squared Error (RMSE). A composite value of RMSE for all customers evaluated will be created to generate a single number for comparison. RMSE was selected for evaluation over R-squared because it describes fit and overall error in a single number. By including overall error in the composite value, we ensure that the impact of larger customers is not lost. For example, if a composite R-

squared value was selected, all values would max out at 1, which would give the same weight to error in a small residential customer as a large industrial customer. For system design it is important that total load is calculated accurately, not that most customers have the least error.

First, a customer composite RMSE will be calculated. This will be a weighted average of the RMSE for all separate time periods regression was performed on focusing on time periods where system peaks are likely to occur. Since system peaks are the focus, only data from January and February will be included in test data. Holidays and days where local time shifts due to DST adjustments will be removed from training and test data. The outline below is a draft and may be updated if results show that peak time periods aren't as expected.

For hourly separations weights are as follows:

- 70% of weight will be given to peak hours (7-9 am)
- 20% of weight will be given to afternoon peak (5-7 pm)
- 10% of weight will be given to all other hours

For daily separations weights are as follows:

- 60% of weight will be given to midweek days (Tuesday to Thursday)
- 30% of weight will be given to weekend adjacent days (Monday and Friday)
- 10% of weight will be given to weekends (Saturday and Sunday)

Once the customer weighted RMSE is calculated, a system RMSE will be calculated. The system RMSE is an average of the customer RMSEs.

Visual Inspection of Results

Model performance may be very close between variations, so visualising results will assist in understanding performance across a range of conditions or customer groups. Graphics will be created to compare actual and modeled values for the following scenarios.

- System profile on selection of coldest / highest demand days.
- Estimated profile under design degree day conditions.
- Temperature/DD vs consumption graphs for selected customer groups.
- Additional graphics as required.

Enbridge Collaboration with Dunsky

Enbridge has over 100 years of experience in gas delivery system design. This makes Enbridge ideally suited to understand the historic practices around demand profiling to ensure that the pilot results can be implemented within the business. The demand extrapolation methodology will build on the company's experience with using historic gate station demand to estimate customer demand across their systems.

Dunsky will be involved in the final selection of the model so that their experience in demand response, regression-based load modeling, and large dataset evaluation can be applied as a 3rd party review.

5. Regression Analysis Model Evaluation

The first step in the analysis will focus on assessing Enbridge's peak load vs hourly weather regression analysis. This assessment will confirm that the methodology appropriately captures customer load sensitivity to weather factors, accurately extrapolates results to design-hour conditions, and provides a sound foundation for subsequent ETEE and DR impact analyses.

The general process to perform this assessment is outlined below. The approach is designed to remain flexible and may be refined as additional data or analytical insights become available over the course of the project.

Stage 1 – Technical Working Meetings

Participate in technical working meetings hosted by Enbridge to review the regression methodology and associated data workflows. These sessions will cover the following topics.

- Background on the hydraulic modeling methodology for design conditions
- Pilot data collection methods
- Visualization of individual, averaged, and grouped customer data
- Hourly estimation model development and validation
- Modeling objectives, data sources, and preparation
- Data analysis processes including a summary of raw data, missing data, and outlier detection processes
- Correlation analysis between gas consumption and weather variables
- Regression modeling approach for baseload and heat load
- Planned model enhancements
- Demonstration to Dunsky of Enbridge's internal Hourly Dashboard for visualizing data

These discussions will provide the technical foundation for understanding the analytical framework and identifying potential enhancements. They will also serve as a forum to ask questions on the current analysis methodologies.

Stage 2 – Sample Data Review

Dunsky will review representative treated data files for each primary data type (ERT, BrightLync, and smart thermostat) to gain familiarity with the datasets used in regression analysis. This review will include verification of: data completeness and timestamp consistency; alignment between consumption and weather variables; route-level and customer-level aggregation methods; and data cleaning and filtering processes.

The goal of this stage is to ensure that the regression inputs are properly structured, validated, and suitable for model estimation.

Stage 3 – Regression Algorithm Review

Review Enbridge's regression algorithm and compare it qualitatively to alternative methods and best practices. Dunsky will apply its expertise in demand response, regression-based load modeling, and large dataset evaluation to assess three key factors.

1. **Extrapolation Approach:** the method used to extend historic load and temperature data to the extreme conditions that define Enbridge's system design criteria (e.g., coldest observed HDH, HDDw).
2. **Customer Segmentation:** the approach used to capture differences among customer types, end uses, and other known drivers of peak demand.
3. **Hourly Dynamics:** the model's ability to represent intra-day load changes (particularly during peak periods) to support analysis of preheating, rebound, and heat pump control behaviour observed in the SLH IRP Pilot.

This review will identify potential enhancements that could improve model robustness and interpretability across customer classes.

To validate reproducibility and model sensitivity, Dunsky will request a **representative random customer sample** (residential and commercial/institutional customers, with stratified sampling to ensure good representation of larger customers) to independently re-run the regression model. This verification exercise will:

- validate model reproducibility and sensitivity;
- identify potential data or coding gaps; and
- support transparent benchmarking of Enbridge's regression process.

The results of the sample data set re-run will be summarized in a supporting workbook, including commentary on data quality and observed variance (if any) between Enbridge's and Dunsky's results.

Stage 4 – Error Evaluation

Identify and, where feasible, quantify individual and cumulative sources of variance inherent in the regression analysis. This assessment will help prioritize areas for methodological or data improvement and support understanding of the uncertainty introduced into subsequent pilot impact evaluations. Examples of potential error sources include:

- model specification bias;
- dependence of regression residuals; and
- regression extrapolation uncertainty under extreme temperature conditions.

Stage 5 – Data Enhancement Opportunities

Identify additional data sources that could strengthen regression accuracy and statistical power. These might include better hourly or other time-differentiated load data, both from a top-down system level (e.g., from Enbridge's operations meters) as well as from bottom-up customer and end-use levels, including real-time measured data (e.g. from hourly ERTs and smart thermostats within SLH) or from more generalized data (e.g. from hourly meter/thermostat data throughout Ontario or from load shapes borrowed from other applications and utilities).

Stage 6 – Summary and Reporting

Prepare a memo outlining our assessment of the regression analysis, the standard error that it may introduce into the forthcoming ETEE/DR Pilot impact evaluation, and its application to future evaluations. The memo will outline any data quality issues and propose potential remedies and include an accompanying workbook with sample data set re-run results.

6. Evaluation Statistical Methods

Section 6 presents an overview the evaluation approach for assessing the impacts of the SLH IRP pilot. Sections 7 and 8 then present detailed evaluation methods, with Section 7 focusing on the assessment of enhanced targeted energy efficiency (ETEE) impacts and Section 8 focusing on the assessment of demand response (DR) impacts. Together, these sections explain how pilot impacts will be calculated and interpreted.

6.1 Control Group Selection

Enhanced Targeted Energy Efficiency

For the ETEE offerings and electrification measures, we will use a combination of pre- and post-treatment data with control groups. Control Group 1 will be selected to include non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics.

To limit self-selection bias, we will attempt to select a control group outside of the SLH treatment region (Group 2), which will be matched to participants based on known (observable) characteristics. Control Group 2 will apply for residential customers only, as hourly interval meter data is unavailable for commercial customers outside of the SLH pilot region.

For electrification measures, customers may or may not participate in other programs, including ETEE offerings. The appropriate control group is thus a mix of non-participants and participants to regular DSM programs, inside and outside of the SLH region (Control Group 1b and Control Group 2b, respectively).

Demand Response

For demand response (DR), control groups are not required, as each participant's baseline load curves will be used to establish the baseline for DR events. This assumes that a few time periods that would normally constitute an event are observed before the program deployment of DR events to create those baseline load curves under extreme weather conditions.

6.2 Control Group Summary

Table 1: Control Group Summary

Pilot Group	Control Group
Enhanced residential whole home DSM offering (1600 expected participants)	Non-participants to DSM offerings inside of SLH region (group 1). Participants to whole home DSM offering outside of SLH region with ERT (group 2).
Enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM (60-150 expected participants)	Non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics.
Electrification measures (ASHPs, GSHPs)	Gas customers (mix of non-participants and participants), inside and outside of SLH region (respectively group 1b and group 2b), matched to electrification participants using known characteristics.
Residential DR pilot (700 expected participants)	No control group needed.

6.3 Statistical Methods

Table 2: Evaluation Methods Summary

Pilot Group	Evaluation Method
Enhanced residential whole home DSM offering (1600 expected participants)	**Peak savings:** regression analysis of control groups vs treatment group hourly usage against weather conditions (outside temperature, wind) for participants with ERTs.
Enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM (60-150 expected participants)	**Peak savings:** regression analysis of control groups vs treatment group hourly usage against weather data (outside temperature, wind) for participants with ERTs.
Electrification measures (ASHPs, GSHPs)	Identify control and treatment group from among participants and non-participants. Apply pre- and post-hourly load analysis to determine peak hour savings. **Peak savings:** regression analysis of pre-post hourly usage against weather data (outside temperature, wind) for participants with ERTs.
Residential DR pilot (700 expected participants)	Establish baseline peak curve and compare to DR response events.

* If any proposed evaluation method results are inconclusive, we will consider supplementing the analysis with engineering algorithms and modeling approaches where they may increase the robustness of the results. Alternate methods for evaluating peak savings involve applying algorithms to calculate peak savings from energy savings using load shapes developed from available meter data, smart thermostat data, available generic end use load curves, past evaluations, etc.

7. Enhanced Targeted Energy Efficiency (ETEE) Evaluation

7.1 Overview and Methodology

The Enhanced Targeted Energy Efficiency (ETEE) evaluation assesses how energy efficiency measures influence peak-hour and design temperature gas demand. The objective is, for the purposes of gas delivery system design, to quantify measurable load reductions (m^3/h) attributable to ETEE interventions while controlling for temperature, customer type, and market trends.

The regression analysis will include the following tasks.

- Clean and assemble billing data, metering data, and program tracking data for all ETEE participants.
- Estimate site-level peak demands for pre- and post-installation periods for participants.
- Identify and remove outliers and other ETEE participants with issues (missing data, inconsistent regression coefficient, etc.).
- Construct a comparison group (group 1 – DSM non-participants) to address non-DSM exogenous change, and a similar comparison group (group 2 – DSM participants) to address non-ETEE exogenous change.
- Determine the average peak savings and savings at design temperature per participant resulting from ETEE participation.

7.2 Statistical Methods

Table 3: ETEE Evaluation Methods

Pilot Group	Evaluation Method
Enhanced residential whole home DSM offering (1600 expected participants)	**Peak savings:** regression analysis of control groups vs treatment group hourly usage against weather conditions (outside temperature, wind) for participants with ERTs, incorporating additional key program data; incorporating smart thermostat data, if available; extrapolated to non-ERT customers based on known usage/building/customer characteristics. Peak hour gas use prior to and after implementation of ETEE measures will be compared to verify that they are statistically different, and the difference between the two curves will be extrapolated to design temperature.
Enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM (60-150 expected participants)	**Peak savings:** regression analysis of control groups vs treatment group hourly usage against weather data (outside temperature, wind) for participants with ERTs, incorporating additional key program data; extrapolated to non-ERT customers based on known usage/building/customer characteristics. Peak hour impacts to be extrapolated to design temperature. • Homogenous group(s), 40-50 or more, identify best targets (segment, annual consumption, etc.). • Potentially collect additional hourly building and/or end use metering data for larger/custom projects. • Apply engineering algorithms to estimate net savings at peak for other customers/measures. • Total savings adjusted using pre/post impacts of control groups.
Electrification measures (ASHPs, GSHPs)	Identify control and treatment group from among participants and non-participants. Apply pre- and post-hourly load analysis to determine peak hour savings. **Peak savings:** regression analysis of pre-post hourly usage against weather data (outside temperature, wind) for participants with ERTs, incorporating additional key program data; extrapolated to design temperatures for peak day/hours; extrapolated to non-ERT customers based on known usage/building/customer characteristics.

7.3 Control Group Selection

For the ETEE offerings and electrification measures, we will use a combination of pre- and post-treatment data with control groups. The pre- and post-treatment data will estimate the impact of energy efficiency and electrification measures, while the control groups will factor in external effects such as energy prices and social trends on naturally occurring energy efficiency and electrification.

Control Group 1 will be selected to include non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics such as size, vintage, etc.

One key consideration when designing the evaluation approach is the possibility of having a self-selection bias in the results. Program participants are self-selected (they choose to participate or not), and this choice may be correlated to building characteristics, consumption profiles, etc. In other words, the program participants may have different characteristics than those of the general population just because they chose to participate in the program.

To limit self-selection bias, we will attempt to select a control group outside of the SLH treatment region (Group 2), which will be matched to participants based on known (observable) characteristics and time of participation in DSM programs. The possibility of creating such a control group will be explored and the outcome may be determined by data availability and data quality. Control Group 2 will apply for residential customers only, as hourly interval meter data is unavailable for commercial customers outside of the SLH pilot region.

Both groups will be matched to pilot participants based on observable characteristics such as annual consumption, building type/segment, etc. This will help alleviate the self-selection bias, although unobservable characteristics may still differ between the control group and program participants.

For the ETEE portion, we will assess the peak hour impacts against two baselines: DSM participants, and non-participants. This will enable us to determine the absolute peak hour impact, as well as any incremental peak hour impact of ETEE when compared to standard DSM offerings. Control Group 1 will be selected among non-participants to assess the overall impact of DSM including the ETEE offering. An analysis of program uptake will complement the evaluation of savings per participant as ETEE can also have the effect of increasing the uptake. Control Group 2 (contingent on data availability) will thus be selected among participants to regular DSM programs to evaluate increased savings (deeper savings) from ETEE.

For electrification measures, customers may or may not participate in other programs, including ETEE offerings. The appropriate control group is thus a mix of non-participants and participants to regular DSM programs, inside and outside of the SLH region (Control Group 1b and Control Group 2b, respectively).

Table 4: ETEE Control Group Descriptions

Pilot Group	Control Group
Enhanced residential whole home DSM offering (1600 expected participants)	Non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics (group 1). Participants to whole home DSM offering outside of SLH region with ERT, matched to ETEE participants using known characteristics (group 2). If possible, control group 2 will be selected in regions that have a similar climate to the pilot's territory.
Enhanced commercial/industrial custom, direct install (DI), and prescriptive DSM (60-150 expected participants)	Non-participants to DSM offerings inside of SLH region, matched to ETEE participants using known characteristics.
Electrification measures (ASHPs, GSHPs)	Gas customers (mix of non-participants and participants), inside and outside of SLH region (respectively group 1b and group 2b), matched to electrification participants using known characteristics. If possible, control group 2b will be selected in regions that have a similar climate to the pilot's territory.

7.4 Limitations and Intended Uses of Results

The evaluation produces empirical results based on observed pilot data; however, the scope, sample size, and data quality constraints inherent to a pilot setting introduce limitations. Thus, the results should be viewed as directional rather than definitive. This section identifies key limitations and clarifies how the results should be applied in future IRP planning.

Limitations

- **Pilot Scale and Duration:** The SLH IRP pilot covers a limited number of participants and a two-year evaluation window. This short timeframe restricts the ability to observe long-term persistence of energy savings or customer behavioural changes. In addition, seasonal variations (e.g., only one or two heating seasons per site) may introduce volatility in estimated savings. Small sample sizes for some customer segments or measures may limit statistical significance and ability to subsegment data.
- **Participant Self-Selection:** Program participants self-select into ETEE offerings, and while matching with control group customers based on known characteristics attempts to correct for this bias, participants may differ from the broader customer population on unobservable characteristics (e.g., building efficiency, equipment vintage, or energy-use behaviour).

- **Statistical Uncertainty:** Regression-based estimates include standard errors and confidence intervals that reflect data variability and model fit. These uncertainties will be reported and should be considered when interpreting numerical savings estimates.
- **Model extrapolation:** The model must be extrapolated outside of the range of observed outside temperatures to evaluate impacts at the system design temperature. Steps will be taken to control for possible bias (e.g. analysing residual errors with outside temperature, testing alternate non-linear models).

Intended Uses

The ETEE pilot evaluation is designed to inform planning. Its findings will guide how IRP Alternatives are valued and assessed with a better estimate of customer uptake, program costs, and peak hour effects. Appropriate uses include the following.

- **Gas Delivery System Design:** With a focus on extreme cold conditions.
- **IRP Assessment Process Learnings:** Providing empirical evidence on the feasibility and magnitude of efficiency-driven demand reduction for system-planning purposes.
- **Program Design Improvement:** Identifying effective measure types, participation drivers, and data-collection practices for future pilots or full-scale programs.
- **Methodological Learning:** Testing regression models, control-group selection methods, and data-integration processes for use in broader IRP applications.

7.5 ETEE Measures Available by Customer Type

Customer Type	Meter Type	ETEE Measures	Notes
Residential	ERT	Insulation (attic, basement, walls); draft-proofing (air sealing); windows, doors, skylights, sliding doors; heat pump water heaters; electric cold climate ASHPs (maximum 20); electric GSHPs (maximum 20); smart thermostats.	Up to $15,000 in upfront full cost coverage. Participants cannot receive an incentive for both a heat pump and home upgrades. It's one or the other.
Small Commercial	ERT	Direct install and prescriptive measures: air curtains; dock door seals; condensing make-up air units; ozone laundry; ventilation; destratification fans; demand-controlled kitchen ventilation; demand controlled (other) ventilation; heat recovery and energy recovery ventilators). Custom options: including but not limited to building automation systems; control upgrades; ventilation equipment; heat recovery.	Direct-install and prescriptive measures: up to $100,000 in full cost coverage. Custom incentive (less uptake for small commercial): $2/$m^3$ up to $250,000 for general commercial and up to $500,000 for industrial, agricultural, and institutional customers.
Large C/I	BrightLync	Same measures as for Small Commercial customers.	Same direct-install, prescriptive, and custom pathways as for Small Commercial Customers.

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7.6 Measurables and Data Evaluation

7.6.1 Residential (ERT)

Control Groups (Non-Participants): Customers outside or inside of the SLH region, matched to pilot participants on consumption and building characteristics. Two control groups will be selected amongst the following customers.

- Non-participants to whole home DSM of ETEE offering inside of SLH region, matched to ETEE participants using known characteristics (group 1).
- Participants to whole home DSM offering outside of SLH region, matched to ETEE participants using known characteristics (group 2).

Sample Group (Participants): Approximately 1600 participating homes are expected in the SLH region.

Measure Breakdowns: Where sufficient participation data exist, results will be disaggregated by measure type to highlight the relative contribution of key residential upgrades. If sample sizes are too small for measure-level analysis, results will be aggregated at the whole-home level with supporting qualitative insights from program tracking data.

The regression results and load-curve analysis will quantify the effects of ETEE in absolute terms (m^3/h) per customer and groupings of customers, forming the basis for system-level extrapolation of residential ETEE impacts.

7.6.2 Commercial (ERT & BrightLync)

Control Groups (Non-Participants): Customers inside of the SLH region, matched to pilot participants on consumption and building characteristics. The control group will be selected amongst the following customers, subject to data availability.

- Non-participants to custom, DI, and prescriptive DSM or ETEE inside of SLH region, matched to ETEE participants using known characteristics.

Sample Group (Participants): The C/I participant group is expected to include approximately 150 facilities located within the SLH region. These sites are enrolled in ETEE programs tailored to their sector and building type. Facilities are equipped with either ERT (for smaller commercial customers) or BrightLync (for larger commercial sites) hourly gas metering. Hourly data from these meters, as available, will be used to perform pre- and post-ETEE regression analyses that relate load to weather and operating conditions, allowing estimation of changes in peak-hour demand and overall energy use. These participant-level results will then be compared with matched control-group customers inside of the SLH region.

Measure Breakdowns

Where sufficient participation data are available, results will be analyzed by major measure type to identify which interventions yield the largest impact. Representative measure categories. If sample sizes for certain measure types are limited, measures may be aggregated by sector (e.g. office, retail, light manufacturing) for statistical reliability.

The regression results and load-curve analysis will quantify the effects of ETEE in absolute (m^3/h) terms per customer and groupings of customers, forming the basis for system-level extrapolation of commercial ETEE impacts.

7.6.3 System Level Impacts of ETEE

The system-level analysis translates customer-level savings into measurable impacts on the SLH regional gas distribution system. Results from the customer-level residential, small-commercial, and industrial regression models will be aggregated to estimate how ETEE participation affects overall system load during critical peak periods.

This aggregation combines:

- the number of participating customers by category;
- average per-customer reductions in peak-hour flow (m^3/h) by category.

Savings from ERT customers will be scaled up to include non-ERT customers. If ERT and non-ERT customers in any given segment differ materially on any observable characteristics (e.g. annual gas consumption, past participation level to DSM programs), then and adjustment factor may be applied to correct for these characteristics, where relevant.

From these data, Enbridge is poised to estimate total peak-hour demand reduction (m^3/h and percent of total load at peak conditions). These values can be compared with modeled system constraints in Enbridge distribution systems to assess whether ETEE measures could meaningfully defer or reduce future infrastructure investments.

7.6.4 Sources of Error

Several potential sources of error may influence the accuracy of ETEE impacts – outlined below.

- Metering gaps or communication losses for customers enabled for hourly interval metering data (ERT/BrightLync).
- Metering gaps for subset of customers within the SLH pilot region that are not enabled for hourly interval metering data.
- Inaccurate installation or participation records.
- Weather station representativeness.
- Regression-model specification errors (to be assessed under load regression evaluation).
- Self-selection bias and other biases.
- Others as determined as the evaluation process progresses.

7.7 ETEE Evaluation Conclusions

The ETEE evaluation will quantify incremental peak-hour reductions achieved through ETEE measures delivery in the SLH pilot region. Expected outcomes:

- quantified peak-hour gas reductions under extreme cold-weather conditions and extrapolated design temperature demand reductions.
- validation of ETEE targeting as a technically viable IRP Alternative by customer segment, measure, approach, or other characteristic.
- actionable insights for improving data collection, program design, and modeling approaches in future IRP assessment processes.

8. Demand Response (DR) Evaluation

8.1 Overview and Methodology

The Demand Response (DR) evaluation assesses how event-based programs influence hourly gas demand within the SLH pilot region. The objective is, for the purposes of gas delivery system design, to quantify measurable load reductions (m^3/h) achieved by participating customers during DR events, and load impacts right before and after events, to determine the reliability, magnitude, and persistence of these reductions under extreme weather conditions.

The DR contractor has agreement with thermostat providers, and event notification varies between providers through in-app notifications and/or emails. DR strategies are still being defined, and evaluation methodology will evolve as the pilot design is finalized.

Unlike ETEE, which compares participants to external control groups, the DR evaluation uses each participant's own pre-event (or non-event) load curve as the baseline (as described in Sections 4 and 6). Hourly ERT data and smart thermostat event data will be used to:

- establish baseline temperature–load relationships under system peak conditions;
- measure changes in gas demand during DR events; and
- assess rebound, persistence, and customer response patterns before and after events.

Regression and event-analysis techniques will be applied to estimate peak load reductions.

8.2 Statistical Methods

Table 5: DR Evaluation Method

Pilot Group	Evaluation Method
Residential DR pilot (700 expected participants)	Establish baseline peak curve and compare to DR response events (including before and after the event horizon to capture pre-heating, rebound and other effects). Design conditions to be extrapolated to understand the impact on system design.

8.3 Control Group Selection

For demand response (DR), control groups are not required, as each participant's baseline load curves will be used to establish the baseline for DR events. This assumes that a few time periods that would normally constitute an event are observed before the program deployment of DR events to create those baseline load curves under extreme weather conditions. We will use hourly data and building-level regression to calculate expected energy use during what would constitute peak events under the program's definition, compare that curve of expected energy use to real energy use for validation, and then use these results to calculate the baseline energy use during events. Modeled energy use (baseline) and real metered energy use (incorporating program impacts) will be compared at the aggregate level (all DR participants) on an hourly and event basis to evaluate peak savings and other program effects (e.g., pre-heating, rebound, etc.).

8.4 Limitations and Intended Uses of Results

The DR evaluation generates high-resolution insights into short-term load flexibility, but results should be interpreted within the constraints of a small pilot-scale program.

Limitations

- **Participant Self-Selection:** Customers opting into the DR pilot may differ from the broader population in thermostat usage, comfort tolerance and responsiveness to DR events. Results of a small pilot project may not be extrapolated to estimate the impacts of a larger program without some adjustments.
- **Baseline Accuracy:** Baselines derived from pre-event periods may not perfectly represent conditions during actual events, for example when occupancy differs.
- **Data Integration:** Synchronizing thermostat and ERT hourly data requires precise time alignment to avoid underestimating or overestimating savings.
- **Limited Persistence Data:** With only one to two DR seasons (dependent on smart thermostat data availability and timeliness), persistence and fatigue effects may not be quantifiable within the evaluation timeframe.

Intended Uses

The DR results will provide directional evidence of the peak-hour load relief achievable through short-duration thermostat control events. Appropriate uses include the following.

- **IRP Assessment Process Learnings:** Estimating the potential of DR to contribute to localized capacity increase deferral as an IRPA.
- **Program Design Improvement:** Identifying optimal event timing, duration, and control strategies for future DR expansions.
- **Behavioural Insights:** Understanding customer participation, comfort preferences, and rebound behaviour for demand-side planning.

8.5 DR Participation and Data Sources

Customer Type	Meter Type	DR Measures	Data Source(s)
Residential	ERT + Smart Thermostat	Event-based heating setback during peak hours via smart thermostats; baseline and event data used to measure load reductions.	ERT hourly consumption, thermostat cloud data.

8.6 Smart Thermostat Data

Smart thermostat data form the foundation of the DR evaluation. These data provide hourly (or sub-hourly, in some cases) data on temperature setpoints and system runtime. These data can be used to quantify DR event participation and customer response/setbacks during peak-hour. Smart thermostat data will be provided with all personally identifiable information (PII) removed.

Temperature Setpoint Data: Capture thermostat's target indoor temperature. Comparing event-hour setpoints to baseline conditions indicates temperature setback magnitude during a DR event. Setpoint recovery profiles following the event can be analyzed to assess customer comfort preferences and post-event rebound.

Integration with ERT Data: Smart thermostat data alignment with ERT hourly gas consumption data enables regression models to link thermostat behaviour directly to measured load changes. This provides supplemental contextual data to correspond smart thermostat setpoint reductions to metered consumption impacts.

DR Event Call Details: Alignment with event call details enables linking between DR event characteristics, customer/thermostat behaviour, and measured load changes. These details include: event hours and duration, event call execution method (i.e. automated, other methods), data capturing manual overrides.

8.7 Measurables and Data Evaluation

8.7.1 Residential (ERT & Smart Thermostats)

Baseline Group (Non-Event): Because the DR analysis relies on event-based comparisons, there is no external control group. Instead, participant baseline load curves will be developed from similar, non-event days with comparable temperature and occupancy conditions. These non-event days may consist of comparable days pre-DR participation and comparable days post-DR participation when a DR event is not called. This baseline represents the customer's expected heating load in the absence of a DR event. Baselines will be built using non-event regression models that relate hourly gas consumption to weather conditions (temperature, wind).

Sample Group (Participants): The participant group will include approximately 700 residential customers that are expected to enrol in the smart thermostat DR pilot. These customers are equipped with ERT hourly meters and internet-connected smart thermostats

capable of automated temperature setbacks during event hours. Hourly gas consumption data will be analyzed to determine weather-normalized changes in gas demand during DR events.

Event Breakdowns: Where sufficient data are available, results will be grouped by event characteristics to highlight factors that most influence consumption (e.g. event duration, event start time, setback magnitude, ambient temperature band, customer participation/opt-in/out/default enrolment). If sample sizes for some segments are limited, events may be grouped by characteristic groups where analytically appropriate.

Effects of DR: The expected effects of DR for the residential sector include the following.

- **Improved load flexibility:** demonstration of customers' ability to reduce or shift gas demand during system peaks.
- **Limited rebound load:** limited post-event heating load increases as thermostats return to normal setpoints or increase to restore space temperature; rebound magnitude and timing to be quantified.

Regression and event-impact analyses will express these effects in both absolute m^3/h per customer.

8.7.2 System Level Impacts of DR

Event-level savings from residential DR program participants will be aggregated to estimate total system-level impacts. This aggregation combines:

- the number of active DR participants;
- average per-customer reductions in peak-hour flow (m^3/h) by category.

From these data, Enbridge can estimate total peak-hour demand reduction (m^3/h) and equivalent capacity relief (m^3/h) for the SLH pilot region. Savings from ERT customers will be scaled up to include non-ERT customers. If ERT and non-ERT customers in any given segment differ materially on any observable characteristics (e.g. annual gas consumption, past participation level to DSM programs), then an adjustment factor may be applied to correct for these characteristics, where relevant.

Observed participation variability, including opt-outs, inactive participants, or partial response, will be incorporated into the system-level calculations to ensure that estimated aggregate impacts represent actual, realized performance rather than theoretical maximum participation. Participation trends will also be tracked over multiple events and up to two heating seasons (2026 and 2027) to assess persistence and program fatigue, subject to smart thermostat data availability and timeliness.

Where DR events do not coincide with design-day temperatures, results can be scaled to design-hour conditions using regression-based temperature sensitivity factors, estimated baseline heat-sensible gas load at design temperature and average gas use reduction. The evaluation will document assumptions and uncertainty associated with this extrapolation, and will also run a regression analysis on the drop of gas use compared to outside temperature using each hour of the DR events as data points to validate or refine this assumption.

8.7.3 Sources of Error

Several potential sources of error may influence the accuracy of DR impact estimates – outlined below.

- Limited number of participants and DR events (smaller data set).
- Missing or incomplete ERT or thermostat data (gaps, communication losses).
- Time misalignment between thermostat and meter readings.
- Weather station representativeness.
- Uncertainty from extrapolating observed impacts to design-hour conditions.
- Changes in hours of operation or process schedules during events that can mask or mimic DR effects.
- Overlap/program interactions of ETEE measures or other DSM activities with DR events.
- Regression model specification errors (to be assessed under load regression methodology evaluation).

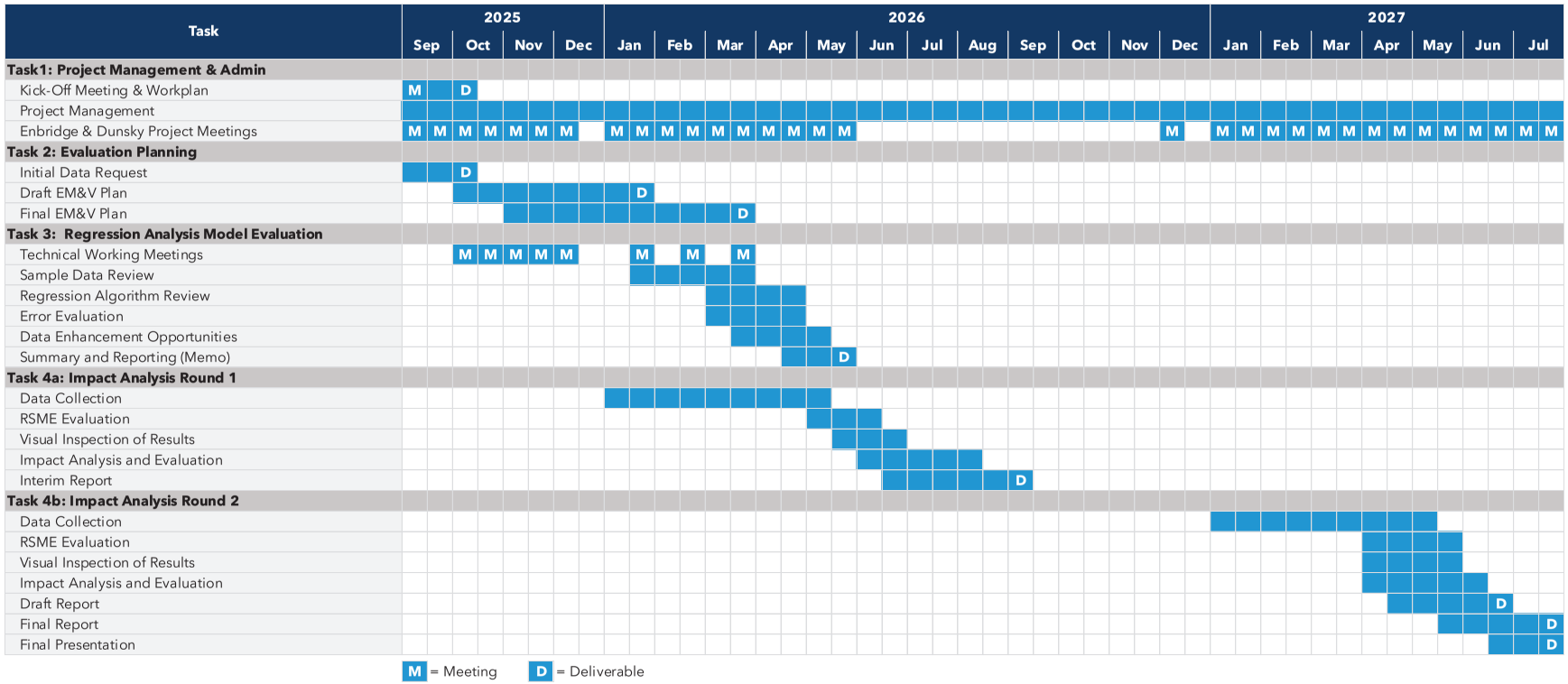
8.8 DR Evaluation Conclusions

The DR evaluation will quantify short term, event-based reductions in residential gas demand achieved through smart thermostat control. Expected outcomes:

- Verified peak-hour demand reductions during cold weather events and extrapolated design temperature peak hour reductions.
- Assessment of rebound magnitude/significance and event consistency.
- Insight into customer behavioural response (overrides under varying conditions).

9. Expected Evaluation Timeline

The following high-level timeline and deliverables are expected for this project.



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10. Reporting

Reporting will summarize findings from the evaluation activities carried out under the SLH IRP Pilot. Each report will include quantitative results, methodological updates, and qualitative insights to inform future Integrated Resource Planning (IRP) applications.

10.1 Interim Report

The Interim Report will provide the first-year impact assessment and evaluation results from the SLH IRP Pilot. It is intended to:

1) present early findings on ETEE and DR program performance;
2) summarize data quality, participation levels, and baseline regression model results;
3) identify preliminary peak-hour load reduction estimates;
4) document lessons learned from data handling, measurement, and evaluation processes.

The Interim Report will be produced after the first full heating season of pilot operation (Q3-2026).

10.2 Final Report

The Final Report will present the complete findings and conclusions from the SLH IRP Pilot once data collection and evaluation activities are complete. This report will serve as the definitive documentation of pilot performance, providing actionable insights for potential scaling of IRPAs. This report will also include the second-year impact assessment and evaluation results from the Pilot.

Contents

- Summary of pilot design, participation, and implementation.
- Final regression model results and validated impact estimates for ETEE and DR measures.
- Discussion of Pilot successes, challenges, and recommendations for future IRP deployment.

The Final Report will be completed in mid-2027, following the conclusion of two full evaluation years and incorporating results from both rounds of analysis (Spring 2026 and Spring 2027).



"NO DISCLAIMERS" POLICY

This report was prepared by Dunsky Energy + Climate Advisors, an independent firm focused on the clean energy transition and committed to quality, integrity and unbiased analysis and counsel. Our findings and recommendations are based on the best information available at the time the work was conducted as well as our experts' professional judgment.
Dunsky is proud to stand by our work.

Indigenous Working Group Report

May 29, 2026

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Appendix A - Enbridge Gas Inc. Indigenous Working Group Meeting Minutes

1. Introduction

As set out in the complete settlement on Item 4 of the Settlement Agreement and accepted by the Ontario Energy Board (OEB) in its Decision on the 2024 Rebasing Phase 1 Settlement Agreement, Enbridge Gas Inc. (Enbridge Gas) established an Indigenous Working Group (IWG)[1] to inform and enhance its ongoing consideration of the unique rights and concerns of Indigenous customers and rightsholders with respect to Enbridge Gas rates and services and has undertaken a number of activities in relation to the IWG. One of the required activities is for Enbridge Gas to work with the members of the IWG to draft an annual report (IWG Report) summarizing the activities of the IWG and initiatives planned or implemented, including minutes of the IWG meetings. This IWG Report is to be filed as part of Enbridge Gas's annual deferral and variance account (DVA) proceeding. This is the second annual IWG Report.

2. IWG Members

The IWG initially consisted of Ginoogaming First Nation (GFN) and the Three Fires Group (TFG), which groups were intervenors in the 2024 Rate Rebasing proceeding. The Settlement Agreement allows for any other First Nation community or reserve to join the IWG provided they or their distribution companies are Enbridge Gas customers. Additional communities (and distribution companies) that have joined the IWG are Minogi Corp, representing Mississaugas of Scugog Island First Nation (Minogi), Chippewas of the Thames First Nation (COTTFN), and Six Nations Natural Gas (together with GFN and TFG, referred to as the Indigenous Parties).

3. IWG Meetings & Minutes

The IWG held meetings on the following dates since the previous annual IWG Report (in-person and virtual):

1. May 14, 2025 — In-person
2. July 15, 2025 — Virtual
3. September 23, 2025 — In-person
4. November 26, 2025 — Virtual
5. March 25, 2026 — In-person

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule1, August 17, 2023, pp.16-20.

Please refer to Appendix A to this IWG Report for copies of the minutes of each meeting.

4. Summary of Discussions

The meetings are managed in accordance with a collaborative approach of determining agenda items and taking turns chairing. Representatives of Enbridge Gas and the Indigenous Parties have attended meetings, shared information and delivered presentations. Overall, the group looks for opportunities to expand on the discussions to provide more information for the OEB and others.

Discussions at meetings are reflected in the minutes appended to this report and included the following topics:

- Leave to Construct (LTC) Environmental Assessment Process
- Responses to The Brattle Group recommendations regarding theenergy transition
- Reconciliation principles
- Heat Pump Strategy Update
- IWG Reporting and Budgeting
- Indigenous Supply Chain Management (SCM) Update
- Engagement Opportunities/Timelines - 2029 Rebasing Filing and Enbridge Projects
- Updated LTC Environmental Assessment (EA) Process
- Integrated Resource Planning (IRP) Process
- Sustainability and Nature-Related Disclosures
- Archaeology firms contracted, and IWG recommendations respecting same
- Relationship with TC Energy
- Bill 5
- 2027 + Demand Side Management (DSM) Plan
- 2029 Rebasing Customer Engagement
- Gas Supply Plan Update

- 2029 Rebasing Indigenous Engagement and IWG Expert Recommendations regarding same
- Methane Measurement related to Enbridge Gas' Assets
- Environmental Report (ER) terminology, including for Archaeological Studies,
- Use of LiDAR for Archaeological Studies and Cumulative Effects Assessments

5. Summary of Presentations to the Group

Meetings include presentations from IWG members and Enbridge Gas subject matter specialists to facilitate informed discussion of a topic. The IWG has received the following presentations and resources in relation to Enbridge Gas:

- May 14, 2025 - LTC Environmental Assessment (EA Process), presented by Enbridge Gas, Kelsey Mills – Supervisor, Environment Projects, who sought feedback from the IWG on opportunities for improvement relating to Indigenous engagement undertaken by Enbridge Gas and explained current initiatives being incorporated into future engagement.
- May 14, 2025 - Response to The Brattle Group recommendations regarding the energy transition, presented by Enbridge Gas, Brent Bullough – Strategist, Community and Indigenous Engagement. The IWG expressed that the responses could be improved and Lisa DeMarco – Resilient LLP, representing TFG and Minogi, provided a list of issues that she would like to see further discussion on, including equity participation, definition of impacts, community specific plans, Brattle misalignment of expectations, and accountability metrics for Enbridge Gas. The IWG suggested continuing the discussion at a future meeting.
- May 14, 2025 - Reconciliation Principles presented by Enbridge Gas, Kim Brenneis – Director, Community and Indigenous Engagement, who provided an update on the status of reconciliation commitments made by Enbridge Inc. since the release of the updated Indigenous Reconciliation Action Plan (IRAP) in April 2025. Following the presentation, discussion ensued around the Indigenous Advisory Group's perspectives surrounding the IRAP.

- May 14, 2025 - Heat Pump Strategy Update, presented by Enbridge Gas, Craig Fernades – Manager, Residential Energy Conservation, who discussed how the strategy has changed since the elimination of the federal carbon surcharge. It was acknowledged there was a need to revisit the topic with COTTFN. Following the update, the IWG expressed interest in getting a third-party to look at cost implications in various scenarios.
- May 14, 2025 - Indigenous SCM Update, presented by Enbridge Gas, Richard Brant – Supply Chain Analyst, Indigenous Engagement, who presented on Indigenous spend statistics and the Enbridge Gas Socio-Economic Requirement of Contractions (SERC) process. Themes of the discussion that followed included potential areas of improvement within the process so that Indigenous businesses could better take advantage of opportunities offered through the SERC process.
- July 16, 2025 - Engagement Opportunities/Timelines – 2029 Rebasing Filing and Enbridge Projects, presented by Enbridge Gas, Vanessa Innis – Director Strategic Regulatory Applications – Rebasing, who sought feedback on Nation participation in the context of the 2029 rebasing consultation. IWG members stressed the importance of customer engagement frameworks and the perspectives of Indigenous Communities in the Regional Scenario Analysis (RSA). Kate Kempton, of Woodward and Company, representing GFN, identified issues and the IWG suggested forming a subcommittee to be involved in consultation. Enbridge Gas advised of upcoming technical sessions and invited IWG members to attend.
- July 15, 2025 - Updated LTC EA Process presented by Enbridge Gas, Kelsey Mills – Supervisor, Environment Projects, who provided an update on the EA process, including the Archaeology Assessment process. Topics included terminology, requirements of archaeologists and LiDAR.
- July 15, 2025 - IRP Process, presented by Enbridge Gas, Alison Moore – Manager, IRP, who sought feedback on the best way to engage the IWG going forward as it relates to the IRP and what the initial focus of the engagement should be. Topics of discussion included the Southern Lake Huron Pilot and the

importance of treaty-based engagement. The IWG suggested organizing a smaller group to discuss.

- July 15, 2025 - Sustainability and Nature-Related Disclosures, presented by Enbridge Inc., Gina Jordan – Manager, Sustainability & ESG Policy, who clarified Enbridge Gas's performance and provided an overview of the Sustainability Report. Gina Jordan discussed ways Enbridge Inc. is working to better understand impacts and dependencies, including continuing to evaluate the disclosure recommendations and guidance set out in the Taskforce on Nature-related Financial Disclosures (TNFD).
- September 23, 2025 - Archaeology firms contracted, and IWG recommendations respecting same, presented by Nicholas Daube – Woodward and Company, representing GFN, who provided an overview of IWG Participant preferred archaeology firms for Enbridge Gas to consider. Enbridge Gas agreed to investigate the list and how suggestions could be incorporated into existing procedures.
- September 23, 2025 - Relationship with TC Energy, presented by IWG, Kate Kempton – Woodward and Company, representing GFN, who expressed disappointment with TC Energy's relationships with GFN. Kate Kempton requested Enbridge Inc. meet with TC Energy to encourage improvement of engagement with Indigenous Communities. Diana Audino, Managing Legal Counsel, for Enbridge Inc. confirmed she would reach out to TC Energy.
- September 23, 2025 - Bill 5, presented by Enbridge Gas, Jessica Maga – Manager, Government Affairs, who attended to answer questions on Bill 5.
- November 26, 2025 - 2027 + DSM Plan, presented by Enbridge Inc., Erin Lindsay – Supervisor, Energy Conservation Business Planning, who provided an update on the approved 2026 DSM Plan and the upcoming 2027+ application, detailing program continuity, budget allocations, and anticipated procedural steps. In addition, the Home Winterproofing Program (HWP), engagement done with First Nations, and attempts to overcome barriers to bringing the HWP to First Nation communities were discussed. Daniel Vollmer – Resilient LLP,

representing TFG and Minogi, requested data on the HWP's uptake in First Nations.

- November 26, 2025 - 2029 Rebasing Customer Engagement, presented by Enbridge Gas Gesiena Antuma – Supervisor, Customer and Market Insights, who sought input on the best way to conduct engagement with Indigenous customers. The IWG requested retaining an expert to help channel First Nations' perspectives, needs, and opportunities.
- March 25, 2026 - Gas Supply Plan Update, presented by Enbridge Gas, Echo Xu – Specialist II, Gas Supply Business Management, who provided an overview of the Gas Supply Plan, including the OEB framework and Enbridge's Gas's supply planning process, inputs to Enbridge's gas supply plan, and Enbridge's 2025/26 Gas Supply Plan and annual update. Topics of discussion included opportunities for First Nations to provide input, Enbridge Gas's relationship with TC Energy and sourcing decisions relating to same, and potential ways to enhance transparency, including reporting on discussions at the IWG.
- March 25, 2026, 2025 - 2029 Rebasing Indigenous Engagement and IWG Expert Recommendations regarding same, presented by Oakview Advisory, Sarah Welch who provided recommendations for future engagement on rebasing. IWG members identified the best method of contact for the Nations they represent. Topics of discussion included current challenges and different ways to facilitate engagement including interviews and Nations reaching out to their members. Nicholas Daube emphasized this as a priority for the IWG.
- March 25, 2026 - Methane Measurement, presented by Enbridge Gas, Luna Munro – Specialist, Carbon Strategy, who discussed the Oil and Gas Methane Partnership (OGMP) 2.0 (including OGMP 2.0 self-assessment), pilot satellite study from 2024, and the Fugitive Emissions Measurement Plan (FEMP), which was included in the rebasing and deferral applications submitted to the OEB. Topics of discussion included OGMP 2.0 self-assessment and methane measurement technologies,
- March 25, 2026 - ER terminology, including for Archaeological Studies presented by Enbridge Gas, Kelsey Mills – Supervisor, Environment Projects, who provided

responses to outstanding IWG items. Enbridge Gas, Stephanie Muller – Advisor, Environment, summarized the archaeology process. Themes of the discussion included appropriate term for 'archaeological resources' when referring to found objects and concluded to go to each community for preferred terminology. This discussion was held on March 25, 2026.

6. Additional, Ongoing, IWG Initiatives

A smaller group within the IWG created a subcommittee to consider Indigenous communities' perspectives on the RSA. A meeting of this subcommittee was held on September 3, 2025.

As noted above, the IWG retained Oakview Advisory to analyze the previous rebasing engagement and recommend ways that future rebasing engagement could be improved. Oakview Advisory met with the IWG and presented their analysis and recommendations on March 25, 2026. There is a reasonable likelihood that they may be further engagement on the basis of those initial recommendations.

In addition, the IWG has retained BDR North America to analyze rates for Indigenous and non-Indigenous customers. This work is ongoing and the IWG expects the analysis and recommendations to be presented at a future IWG meeting.

7. IWG Capacity Funding for 2027

Under the OEB-approved Settlement Agreement, Enbridge Gas is required to provide capacity funding for the reasonable costs of each of the Indigenous Parties for their preparation for and participation in the IWG meetings, which includes reasonable technical expert and legal assistance necessary to engage meaningfully on the topics the IWG addresses, as well as to establish a budget reflecting estimated capacity funding for the following year. Actual capacity funding costs incurred are recorded in Enbridge Gas's IWG deferral account and will be subject to review and clearance in the applicable DVA proceeding.

The IWG is presenting the 2027 estimated budget for review by the OEB as part of the DVA proceeding. The Indigenous Parties propose an estimated budget for capacity funding for the calendar year 2027 of $640,000, described as follows:

1. There is a desire to increase Indigenous community membership on the IWG, and in particular those communities which Enbridge Gas services. As membership increases, we expect there to be increased representation and coordination costs.
2. There is an expectation that 2027 will continue to see a need for legal and technical expert assistance, especially in light of the work being undertaking for the 2029 rate rebasing application expected to be filed in 2027, as well as the priorities that the participating First Nations and Enbridge Gas continue to advance as areas of focus for the IWG.
3. The requested capacity funding costs for the IWG for 2027 are:
    i. $242,000 for legal support;
    ii. $202,000 for consultants and First Nation representatives; and
    iii. $196,000 for experts.

Enbridge Gas will pay the capacity funding based on actual reasonable costs incurred and appropriately invoiced by the Indigenous Parties to participate in the IWG.

8. Additional Perspectives from the Indigenous Parties

The IWG recognizes the importance of reflecting the perspectives of the Indigenous Parties in the context of a summary of the IWG's activities.

Accordingly, the Indigenous Parties and Enbridge Gas have collaboratively developed the following new section of the Annual Report. The purpose of this section is to provide additional context regarding the IWG's activities, including matters of particular importance to the represented First Nations as Treaty and section 35 rightsholders, as well as opportunities for continued advancement of the IWG's objectives.

The Indigenous Parties view the inclusion of this section as an important step toward ensuring that their perspectives form part of the Annual Report. The Indigenous Parties and Enbridge Gas are committed to continuing to work together through the IWG to

further refine and enhance this section in future annual reports so that it continues to meaningfully include the perspectives of the Indigenous Parties.

The Indigenous Parties continue to view the IWG as an important forum for engagement, recognizing that, like any forum, there is always an opportunity for continuous improvement and development over time. They view the IWG as an important forum to express their priorities, to exchange ideas and information and engage in substantive discussions with Enbridge Gas (often with the benefit of company or external experts), and ideally to make meaningful progress on energy-related issues of importance to the represented First Nations and their members.

The Indigenous Parties believe that there will be continued opportunities that will present themselves to fully realize the IWG's potential. To this end, they would like to see Enbridge Gas continue to build on its existing support and investment in relation to the issues of highest priority to the Indigenous Parties and reconciliation more generally.

For example, one area of particular interest for many or all of the Indigenous Parties is continuing meaningful conversations on measures that would meaningfully contribute to economic reconciliation. These conversations should reflect the fact that Enbridge Gas's operations and infrastructure exist within territories of the represented First Nations, and that appropriate Project mitigations and any additional accommodation that may be required should be considered in this context.

The Indigenous Parties believe that the IWG has served as an important forum for discussions and information exchanges on other issues of importance, as detailed throughout this report. They believe that will continue to be the case over the coming year, with an anticipated focus on the following issues of importance to each of the Indigenous Parties, among others to be identified over the course of the year:

- Enbridge Gas rates as they relate to Indigenous customers;
- Enhancements to Enbridge Gas's customer engagement practices relating to Indigenous customers to continually improve responsiveness to their priorities and interests;
- Integrated Resource Planning and related Enbridge Gas programs;

- Enbridge Gas's archaeological practices as they relate to Indigenous peoples, their lands and cultural heritage and patrimony;
- Enbridge Gas's practices in relation to the employment of Indigenous peoples and its engagement of Indigenous businesses;
- Environmental, climate, and nature-related issues of consequence to the Indigenous Parties as they relate to Enbridge Gas's business;
- To the extent it relates to Enbridge Gas's business, energy transition consequences for Indigenous peoples and ways the impact of energy transition on Indigenous customers can be mitigated; and
- Reconciliation and economic reconciliation in relation to Enbridge Gas's business.

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held on **May 14, 2025,** at 10:00 a.m. at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Lisa DeMarco	Resilient LLP, Three Fires Group, Minogi Corp
Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Todd Jardine	Three Fires Group
Nicholas Daube	Woodward and Company, Ginoogaming First Nation
Tracy Skye	Six Nations Natural Gas
Bruce Tsuchida	The Brattle Group
Peter Fraser	The Brattle Group
Richard Brant	Enbridge Gas Inc.
Henry Ren	Enbridge Gas Inc.
Kris Geekie	Enbridge Gas Inc.
Diana Audino	Enbridge Gas Inc.
Kim Brenneis	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Arend Wakeford	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Jennifer Cittadini	Enbridge Gas Inc.
Craig Fernandes	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Erin Nolan	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.

Note on usage of “Enbridge Inc” and “Enbridge Gas Inc”: Policies and plans, such as the Indigenous Reconciliation Action Plan are Enbridge Inc. documents that apply to the whole company including Enbridge Gas Inc. For the purposes of IWG meetings, Enbridge staff are representing Enbridge Gas Inc.

MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
   - Lauren Whitwham chaired the meeting, consensus to continue to rotate the facilitator/chair of each IWG meeting.
   - Gabby Lapalme provided a safety moment.
   - IWG agreed to take approval of March 4, 2025 minutes back and provide written comments.
   - Brent Bullough outlined the agenda for the meeting.
     - Enbridge Gas Inc. is seeking comments from the IWG on the Engagement Template and Lifecycle guidelines.

2. Enbridge LTC Environmental Assessment Process
   - Kelsey Mills presented on Enbridge Gas Inc's Environmental Assessment (EA) Process, highlighting Indigenous Engagement as a key element for project development, planning, and review.
   - Kelsey Mills sought feedback from the IWG on opportunities for improvement throughout the process and potential areas of focus for the presentation.
   - Lisa DeMarco asked if Kelsey Mills could provide slides and Kelsey Mills advised that the presentation is in early stages and the idea would be to create a more targeted presentation for the next meeting based on feedback from the IWG.
   - Rob Lukacs stated that Mississaugas of Scugog Island First Nation (MSIFN) are treated like stakeholders opposed to rights holders throughout the EA process and that Enbridge Gas Inc. treats the Ontario Energy Board (OEB) requirements as a be all end all. Rob Lukacs stated that Enbridge Gas Inc. is not limited by OEB requirements and that they should be more receptive to feedback. Rob Lukacs indicated that the Mississaugas of Scugog Island First Nation (MSIFN) is prepared to share feedback with Enbridge Gas Inc. but it is difficult when they are not offered the opportunity to attend field studies during the EA.
   - Kelsey Mills advised that participation during field verification (windshield) surveys was historically not a practice. Going forward, Enbridge Gas Inc. will invite Indigenous communities to participate and provide traditional knowledge during field verification surveys and archaeology field visits, to encourage early engagement. Additionally, after the Notice of Commencement (NOC) is distributed, Enbridge Gas Inc. will provide an environmental screening memo to Nations indicating what exists in the area through an initial desktop review of available materials.
   - Rob Lukacs advised that it would be meaningful to have most of the information available during the NOC (transparent communication), going beyond the Crown requirement. For example, the impacts on certain species. He further emphasized Enbridge Gas Inc. not recognizing First Nations as working partners. A commitment from Enbridge Gas Inc. is needed with regards to capacity funding, timelines, and the work being done.
   - Lauren Whitwham confirmed that Enbridge Gas Inc. offers capacity funding on all projects and asks the Nations to advise on the amount they require to engage.
   - Lisa DeMarco asked that timelines consider Nations' need to gather capacity.
   - Kelsey Mills agreed that there are opportunities to investigate the timelines and to potentially provide more time for early engagement preparation. With regards to opportunities, there needs to be an ongoing dialogue with Nations.
   - Diana Audino emphasized that it is helpful for Nations to provide quotes for capacity funding.
   - Nicholas Daube advised that it would be helpful to see the points in the process where experts (archaeological, environmental, etc.) are included.
     - Lauren Whitwham suggested that this could also include proposed dates and the documents that need to be reviewed. For example, in the form of a Gantt chart included in the NOC.
   - The IWG is interested in seeing the opportunities for Indigenous employment.
   - Rob Lukacs advised that a Principles of Ownership agreement is being worked on by MSIFN and can be shared with Enbridge Gas Inc.
     - Diana Audino advised that Enbridge Gas Inc. can also enter into data protection agreements extending to consultants with Nations.

- Kelsey Mills confirmed she would add information about the archeology and built cultural heritage process to the next presentation along with opportunities for monitors. Kelsey Mills also spoke on how Nation histories can be included in Stage 1 reports.
- Rob Lukacs brought up Bill 5 and is seeking to understand Enbridge Gas Inc.'s engagement expectations in special economic zones and proposed discussing it at the next IWG meeting. Rob Lukacs is also wondering if Enbridge Gas Inc. is lobbying the government to become a trusted proponent and if this would change engagement priorities. Rob Lukacs advised that Bill 5 would have lots of impact on treaty rights and processes.
    - Kelsey Mills advised that it would be on the proponent (Enbridge Gas Inc.) to work ethically and responsibly, specifically with respect to impacts on Species at Risk.
- Lisa DeMarco brought up the Taskforce on Nature-related Financial Disclosures (TNFD) and asked what Enbridge Gas Inc.'s oversight is for governance around nature related dependencies and impacts on nature. Specifically, how these dependencies feed up the organization and what Enbridge Gas Inc. has committed publicly.
- Rob Lukacs emphasized that MSIFN has been bringing this up since 2023.
- Lisa DeMarco referenced where TNFD is addressed in Enbridge Gas Inc.'s Sustainability Report
- Todd Jardine advised that getting things in early stages would be helpful to be aware of what is going on with projects.

3. Enbridge Response to The Brattle Group Recommendations
    - Brent Bullough provided an update on Enbridge Gas Inc.'s response to The Brattle Group's (Brattle) recommendations.
    - Brent Bullough advised that Enbridge Gas Inc. does not intend to update the pathways to net zero studies at this time. The Regional Scenario Analysis (RSA) is to feed into future filings.
    - Lisa DeMarco advised that clients feel the responses are inadequate and delayed and do not take accountability. For example, the response to the energy transition is inadequate. They advised that going forward, it would be good for Brattle and the First Nations to speak to the RSA team.
    - Bruce Tsuchida emphasized that the recommendation to provide a timeline of a project and opportunities for local inclusion was requested and the response was inadequate, and the overall responses were underwhelming.
        - Lauren Whitwham offered to provide a generic schedule of the engagement process.
    - Lisa DeMarco advised that the next filing is scheduled for 2029, but engagement should start in 2025.
        - Nicholas Daube agreed with this and recommended that the second paragraph from EGI's responses to the Brattle recommendations should start now, being EGI's commitment to "review and discuss with the IWG how best to include ETP potential impacts on indigenous communities (i.e. on community-level and/or daily lives)….".
            - Brent Bullough confirmed that participation would start soon, and the team is putting together timelines.
    - Lisa DeMarco requested the specific breakdown of the process to the 2029 filing and advised that energy related risk is related to nature related risk and dependencies for energy transition.
        - Lauren Whitwham confirmed that the timeline isn't finalized yet.
        - Nicholas Daube confirmed that whatever is available in the next month would be good.
    - Nicholas Daube brought up the second recommendation related to equity participation and advised that it is helpful to keep this on the agenda.
        - Kim Brenneis confirmed that many partnerships have been completed and are ongoing.

- Lisa DeMarco provided a list of key discrepancies and confirmed to follow up with them in an email:
    - Commitment to equity
        - The recommendation was clear, and the response referred to the Indigenous Reconciliation Action Plan (IRAP)
        - Crystalizing actionable items is important (i.e. co-signing a consultation framework with the IWG)
        - Equity partner targets in Ontario
        - Independent oversight (Indigenous led oversight to review report on reconciliation and resurgence efforts – accountability to Nations)
        - Fair compensation
    - Recognizing what falls under impact
        - First Nation vulnerabilities
        - In-person meetings
        - Early engagement
        - Process structure
        - Recommendation for engagement protocol
        - Developing a protocol mandating project meetings impacting traditional territories
        - Go beyond environmental assessment
        - The IWG hoped to provide feedback on the IRAP
    - Community specific plans
    - Brattle misalignment of expectations
        - IWG is seeking more action
    - Accountability metrics for Enbridge Gas Inc.
        - What is tracking and reporting on engagement for Enbridge Gas Inc.
        - Showcasing results (i.e. Online dashboard, where we are, what can we do better, etc.)
        - Proactive updates
        - Accountability metrics
        - Impacts, co-development (combining expertise and knowledge)
        - Be creative with media to share historical knowledge and experiences, cultural sensitivities
- Kim Brenneis emphasized from the last meeting that Enbridge Gas Inc. does not pay historical compensation for land use and Enbridge Gas Inc. sees equity as a commercial opportunity.
- Lisa DeMarco clarified that they meant framework as opposed to formula.
- Nicholas Daube advised they would take this discussion back to Kate Kempton for comments.

4. Enbridge Reconciliation Principles
    - Kim Brenneis provided an update on Enbridge Gas Inc.'s Reconciliation Principles since the release of the IRAP refresh in April 2025.
    - Enbridge Gas Inc. has achieved 12 of the 22 commitments. Five of those were integrated into Enbridge's corporate DNA and are no longer in the IRAP Refresh, and seven were achieved and remain in the Refresh. Twenty new or refreshed commitments comprise the IRAP Refresh for the next 3 years, with the progress to be reported on in the Sustainability Report (the IRAP as a living document)
    - Enbridge Gas Inc. is seeking to build the Lifecycle approach into processes.

- Kim Brenneis advised that the Indigenous Advisory Group (IAG) continues to provide perspectives and advice to senior management and is not representative of a specific Nation or group.
- Nicholas Daube asked what the IAG was most excited for and what they continue to push for.
    - Kim Brenneis said the IAG was most excited by the implementation of the IRAP and the progress made. They advised that the IAG continues to press for procurement and employment especially in a North American context. They also want to see a better reflection of the communities Enbridge Gas Inc. works in.
- Lisa DeMarco asked about the IAG members
    - Kim Brenneis explained that historically they have not shared names of members as per their request. The IAG feels they are best able to provide perspective without the members being publicized. IAG members respectfully decline meeting with the IWG.
    - Lisa DeMarco asked if the IWG can see the IAG meeting presentations/ notes.
    - Kim Brenneis advised that IAG members are not speaking on behalf of a rights bearing group just their individual experiences and perspectives.
    - Lisa DeMarco advised that Senior management and the Board of Directors are acting on behalf of the IAG so it would be helpful to gather more transparency.
    - Tracy Skye asked how someone becomes a member of the IAG.
        - Kim Brenneis advised that Enbridge Inc. worked with a consultant to identify leaders in different spheres (i.e. academic, business, etc.). Enbridge Inc. was then provided a list of people across North America and then there was a selection process.

5. Filing of OEB Report on IWG and 2026 IWG Budget
    - Lauren Whitwham reviewed the current version of the OEB report.
    - Rob Lukacs suggested switching language of Indigenous Way of Life and Stewardess to Inherent Responsibilities of the Land.
        - Lauren Whitwham confirmed that the original language was from Kodi Deleary and the IWG agreed to keep it how it is, and Lauren Whitwham confirmed to capitalize the title.
    - Lauren Whitwham confirmed to send out the report to the IWG for feedback on budget, amount changes and rationales.
    - Section 6. IWG Capacity Funding
        - Nicholas Daube suggested and the IWG agreed that it would be helpful to give everyone the full context of the number and reproduce some text from the Settlement Agreement.
    - With regards to the high legal fees, Lauren Whitwham explained Resilient LLP's role and the Brattle Report.
    - Lauren Whitwham confirmed to send an email including the Report for review and comment and confirmation of March meeting minutes
        - Regulatory is giving until May 24, 2025 for the Report
    - Nicholas Daube asked if the presentations could be included in the minutes.
        - Tania Parsad said there should not be a concern with this, but they would need to confirm with other parties (i.e. Brattle).
6. Heat Pump Strategy Update
    - Craig Fernandes provided an update on the heat pump strategy since the federal carbon surcharge is now zero. They have to circle back with Chippewas of the Thames First Nation (COTTFN) to discuss further.

- Nicholas Daube advised that it is important for people to understand what they are getting into and there is a lot of dispute in OEB proceedings regarding the range of cost implications of the technology.
- Nicholas Daube asked if it is possible to get a third-party expert to look at cost implications in various scenarios.
    - This topic would need to be revisited with COTTFN
    - Enbridge Gas Inc. and IWG to look to see if there is someone/ organization to do this
    - Craig Fernandes thought it would be possible and beneficial. They also confirmed they would be transparent.
    - Rob Lukacs also agreed to an independent review.
    - Rob Lukacs advised that there is no carbon charge scenario and asked if the incentives were linked to policy included in the analysis.
        - Craig Fernandes confirmed that they were referring to operational cost for the pilot and not the cost to participants.

7. Enbridge Indigenous Supply Chain Management (SCM) Update
    - Richard Brant provided an update on Indigenous SCM.
    - Richard Brant provided Indigenous spend statistics from 2017-2025 and noted that 2025 spend is low so far because construction starts in the summer. Richard Brant discussed the Socio-economic Requirement of Contractors (SERC) and broke down the types of businesses and services they look for. They also noted that in Ontario there are not as many projects being planned. To work directly for Enbridge, businesses go through ISN (ISNetworld) safety assessments to be given a green, yellow, or red status. Green and yellow can work for Enbridge Gas Inc. and they are working on developing a feedback mechanism for Indigenous businesses.
    - Nicholas Daube noted that the third bullet on the Important Considerations slide is an area for opportunity. They advised that one issue is that any contract from Enbridge Gas Inc. would not be completely sufficient for operations for an Indigenous business.
    - Richard Brant explained that there are two parts: What Enbridge Gas Inc. needs and what a Nation business can provide. There are also two types of opportunities: smaller jobs for existing businesses and bigger jobs that businesses would need to build toward to be considered.
    - Kim Brenneis reinforced that Enbridge Gas Inc. is open to how Nations see themselves economically on their journey.
    - Nicholas Daube discussed an opportunity to improve information deficits and understanding for Nations to capitalize.
    - Richard Brant emphasized the importance of having the right person at the community with the knowledge to best situate their businesses. They further emphasized that engagement can begin 1-2 years in advance because Enbridge Gas Inc. can foresee work that will need to be done.
    - Nicholas Daube asked if anything similar has been done in other provinces and Richard Brant confirmed there has been.
    - Tania Persad advised there is lots of publicly available information about planned activity and opportunities for development.
8. Action Items
    - Item 1: Enbridge Gas Inc. to provide meeting minutes from IWG meeting on March 4, 2025, with the IWG for comments and approval.
    - Item 2: Enbridge Gas Inc. to provide the IWG Report with March's meeting minutes (seeking feedback specifically on budget, amount changes and rationale). Enbridge to capitalize the title of

the OEB Report, include language from the Settlement Agreement in the updated budget, and confirm if power point slides from the March 2025 meeting can be included in the minutes.

- Item 3: Enbridge Gas Inc. to add the archaeology process into the next Environmental Assessment Process PowerPoint.
- Item 4: Rob Lukacs to share Principles of Ownership agreement being developed by MSIFN with Enbridge Gas Inc.
- Item 5: Enbridge Gas Inc. to include Bill 5 on the next IWG meeting agenda.
- Item 6: Enbridge Gas Inc. to provide information about the company's oversight for governance around nature-related dependencies and impacts on nature, related to TNFD and how these dependencies feed up the organization and what Enbridge Gas Inc. has committed to publicly.
- Item 7: Enbridge Gas Inc. to provide a generic schedule of the engagement process.
- Item 8: Enbridge Gas Inc. to provide the timeline for the 2029 filing when it becomes available.
- Item 9: Lisa DeMarco to follow up with an email outlining the key discrepancies between the Brattle Recommendations and Enbridge Gas Inc.'s initial responses discussed at the meeting to be included in the minutes.
- Item 10: Enbridge Gas Inc. to see if they can provide the IAG meeting presentations/ notes to the IWG.
- Item 11: Enbridge Gas Inc. to revisit heat pump discussion with COTTFN.
- Item 12: Enbridge Gas Inc. and IWG to see if there is someone that could do an independent review of cost implications for different scenarios with regards to heat pumps.

NEXT MEETING

Next meeting of the IWG is tentatively set to take place virtually in July/August and the date to be canvased by email.

APPENDIX A – AGENDA FOR MEETING OF IWG ON MAY 14, 2025

Time	Matter	Participants
10:00-10:15 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Lauren Whitwham and Group
10:15-10:30 am	Enbridge LTC Environmental Assessment Process	Kelsey Mills and Erin Nolan
10:30-11:45 am	Enbridge Response to The Brattle Group Recommendations	Enbridge and Group
11:45-12:15	Enbridge Reconciliation Principles	Kim Brenneis
12:15-1:00 pm	Lunch	
1:00-1:45 pm	Filing of OEB Report on IWG and 2026 IWG Budget	Lauren Whitwham and Group
1:45-2:00 pm	Heat Pump Strategy Update	Jennifer Cittadini and Craig Fernandes
2:00-2:30 pm	Enbridge Indigenous SCM Update	Richard Brant
2:30 pm	Wrap-up/Adjourn	Group

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held virtually on **July 15, 2025,** at 9:00 a.m.

PRESENT

Lisa DeMarco	Resilient LLP, Three Fires Group, Minogi Corp
Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Todd Jardine	Three Fires Group
Rick Peters	Three Fires Group
Kate Kempton	Woodward and Company, Ginoogaming First Nation
Nicholas Daube	Woodward and Company, Ginoogaming First Nation
Shelly Rahme	Ginoogaming First Nation
Kodi Chrisjohn-Deleary	Chippewas of the Thames First Nation
Peter Fraser	The Brattle Group
Diana Audino	Enbridge Gas Inc.
Richard Brant	Enbridge Gas Inc.
Jennifer Murphy	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Arend Wakeford	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Richard Lanni	Enbridge Gas Inc.
Gesiena Antuma	Enbridge Gas Inc.
Vanessa Innis	Enbridge Gas Inc.
Cara-Lynne Wade	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Henry Ren	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Levi Gordian	Enbridge Gas Inc.
Heidi Steinberg Laxton	Enbridge Gas Inc.

Note on usage of "Enbridge Inc" and "Enbridge Gas Inc": Policies and plans, such as the Indigenous Reconciliation Action Plan are Enbridge Inc. documents that apply to the whole company including Enbridge Gas Inc. For the purposes of IWG meetings, Enbridge staff are representing Enbridge Gas Inc.

MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
    - Brent Bullough chaired the meeting.
    - Gabby Lapalme provided a safety moment.
    - Approval of May meeting minutes
        - Kodi Chrisjohn-Deleary indicated support of the Ontario Energy Board (OEB) Report presentation name change suggested by Rob Lukacs from Indigenous Way of Life and Stewardess to Inherent Responsibilities of the Land.
        - Kodi Chrisjohn-Deleary mentioned that Chippewas of the Thames (COTTFN)'s perspective on heat pumps has changed and Lauren Whitwham suggested setting up a separate meeting to discuss this.
            - Lisa DeMarco requested that the heat pump discussion be extended to the rest of the IWG.
        - Lisa DeMarco advised that updates to the May minutes would be provided in an email.
        - Enbridge Gas Inc. and the IWG agreed to take the approval of the May 14, 2025 minutes back until additional edits were incorporated
    - Status of May meeting's Action Items
        - Item 5: Enbridge Gas Inc. to include Bill 5 on the next IWG meeting agenda.
            - Brent Bullough confirmed to put a discussion on Bill 5 on the September meeting's agenda.
            - Rob Lukacs asked if Enbridge Gas Inc. is going to request to be a trusted proponent in special economic zones.
            - Lisa DeMarco asked for a summary of any lobbying activity surrounding Bill 5.
                - Brent Bullough confirmed that a statement on the Economic Zones Act was filed, and they would see if it could be shared with the IWG along with lobbying activity.
            - Kate Kempton advised that they had filed an application to strike out Bill 5 and key aspects of Bill C-5.
                - Kate Kempton advised that companies that stand behind Bill 5 would lose Nation support.
                - Kate Kempton discussed how the Endangered Species Act authorizes the permanent wiping out of species. They advised that Bill 5 is going back to when there was no engagement. They clarified that they are not against economic opportunities but want First Nations at the table.
                    - Kate Kempton confirmed to circulate the Notice of Application to Enbridge Gas Inc. and the IWG.
        - Item 9: Lisa DeMarco to follow up with an email outlining the key discrepancies discussed at the meeting to be included in the minutes.
            - Lisa DeMarco confirmed they are working on this.
        - Item 10: Enbridge Gas Inc. To see if they can provide the IAG meeting presentations/ notes to the IWG.

- Lauren Whitwham confirmed they are working on this.

2. Engagement Opportunities/Timelines - 2029 Filing and Projects
   - Vanessa Innis presented on 2029 Rebasing.
   - Lisa DeMarco asked about the approach to consultation and what data is available.
     - Vanessa Innis clarified that they are looking for specific feedback on where Nations would like to be involved (e.g. Depreciation study).
     - Lisa DeMarco advised that Nations would be interested in all aspects of the rate case, specifically capital growth models and rate base.
     - Vanessa Innis advised that they do not have data yet about forecast underpinnings and indicated that the proposal would be going through the forecast process in 2027.
   - Gesiena Antuma advised that they are working through a plan for customer engagement and are looking to understand the best way for engagement.
     - Lisa DeMarco requested the general customer engagement framework and rights holder engagement framework.
   - Jennifer Murphy presented on the First Nation Engagement Approach and the Regional Scenario Analysis (RSA).
     - Jennifer Murphy proposed a discussion-based session in mid- to late-August with the IWG and Indigenous communities that are served by EGI to seek input that could be incorporated into the RSA.
       - Lisa DeMarco asked for clarification about what the meeting would be.
         - Jennifer Murphy confirmed that this would be the consultation.
       - Lisa DeMarco advised that the nature of the consultation itself would be highly contingent on the development of content and what is in the proposal.
         - Lisa DeMarco emphasized the importance of requests from First Nations reflected in the RSA proposal.
         - Rob Lukacs and Todd Jardine agreed.
       - Kate Kempton identified two issues;
         - Climate change and the need to get off GHG emissions needs to be addressed in the RSA and the IWG needs to be included.
         - Revenue sharing between Nations whose lands are being used.
         - Jennifer Murphy advised that this is not necessarily part of the RSA which would focus on creating a forecast of demand and would then look to make plans and incorporate First Nation input into this.
           - Looking at what kind of information the Nations could contribute.
           - Kate Kempton advised that demand is partly constructed by the company (i.e. Lobbying efforts impact demand).
           - Lisa DeMarco proposed forming a subcommittee of the IWG to work on skeleton elements of the RSA.
             - Cara-Lynne Wade suggested that a next step could be to work with one or two people on the IWG.
               - Cara-Lynne Wade clarified that the initial piece of work is not looking at the likelihood of scenarios but about which scenarios they could model to understand the impact on demand, customer

count, etc., and looking to ensure that they are modeling ones that are valuable.

- Lisa DeMarco advised that a number of IWG members have experience creating scenarios and could contribute.
    - Cara-Lynne Wade asked who they should consult on the IWG and Lisa DeMarco volunteered.

- Jennifer Murphy asked what other nations not represented on the IWG that Enbridge serves would want to be involved.
    - Lisa DeMarco suggested Peter Fraser (Brattle Group).
- Jennifer Murphy also advised that technical sessions with external parties are being planned to provide an overview of RSA scenarios.
    - Jennifer Murphy asked if anyone is interested in participating in the technical session on July 30.
        - Lisa DeMarco and Nicholas Daube confirmed they would like to attend.

3. Enbridge Updated LTC Environmental Assessment (EA) Process

- Kelsey Mills presented on the Environmental Assessment Process.
    - Rob Lukacs advised that First Nations need to be working with Enbridge to come up with preferred routes.
        - Kelsey Mills advised that this is part of the Notice of Upcoming Project where Enbridge Gas Inc. seeks input on routes. Kelsey Mills also advised that the process is being modified to better work with communities. Recently and going forward Nations are invited to field verification surveys.
- Lisa DeMarco suggested changing the language of ‘confirmation of preferred route’ to ‘determination of preferred route’.
    - Rob Lukacs further advised that they take issue with language of ‘Incorporation of Treaty Rights and Indigenous Knowledge’ and requested it be changed to ‘Weave Treaty Rights and Indigenous Knowledge into Mitigation Measure Development’.
        - Kelsey Mills confirmed to investigate changing this.
- Archaeology Assessment (AA)
    - Lisa DeMarco emphasized the importance of having adequate monitors to participate in field work.
        - Kelsey Mills advised that Enbridge Gas Inc. recognizes this and offers opportunities to be involved and provides capacity funding for this.
        - Rob Lukacs asked what level of information informs the cumulative effects assessment in respect to archaeological resources.
            - Kelsey Mills confirmed to take this back to the team.
        - Nicholas Daube asked if there is a requirement for people doing the assessment to have experience with First Nations, and further, if there is an opportunity for First Nations to have a say in the selection of people performing the studies.
            - Kelsey Mills advised that the standard for assessments and consultation with First Nations by archaeologists is set by the Ministry.
                - Rob Lukacs responded to Nicholas Daube indicating that Enbridge should have an internal policy including one that contains the

requirements including processes of identification of artifacts and it should be dedicated to requirements at each stage of the process. Rob Lukacs advised that Nations should be able to help develop this internal policy.
- Kelsey Mills advised that they would see if an internal policy could be shared with the IWG.
- Nicholas Daube advised that this is part of a bigger discussion on internal policies.
- Lauren Whitwham confirmed that archaeology work is done by licensed archologists.

- Lisa DeMarco asked to what extent LiDAR is being used along the full preferred route.
- Kelsey Mills advised that they typically don't get to a Stage 3 or 4 as the priority is to put the pipe into previously disturbed corridors. Enbridge Gas Inc. doesn't want to be limited to just looking for burials.
- Lisa DeMarco suggested Enbridge Gas Inc. work with archeologists to create a cost benefit analysis of LiDAR along the full preferred route.
- Daniel Vollmer asked what the ministry standard is for what an expert archaeologist needs to know when it comes to cultural significant matters.
- Kelsey Mills confirmed that Enbridge Gas Inc. does try to go beyond what is required by the ministry.
- Nick Daube advised that ensuring adequate attention to both documented records and community knowledge is a challenge. He asks how Enbridge Gas Inc. ensures that the experts have the resources available to address areas of greatest consequence to First Nations and in a way that they are not just relying on the Nations to fill in the gaps. Nick Daube suggested further discussion.
- Kodi Chrisjohn-Deleary noted that Nations have preferred archaeology firms.
- Kelsey Mills advised that they would be interested in knowing what these firms are and agreed that additional discussion on archaeological expert knowledge and expertise would be beneficial
- Shelley Rahme noted the language of ‘resources’ in the presentation should be changed to ‘assets’.
- Kelsey Mills advised they would investigate changing this.

- Nicholas Daube asked Rob Lukacs if there was anything else being done by other proponents that could be proposed to Enbridge.
- Rob Lukacs agreed that these questions are worth pursuing but understanding Enbridge Gas Inc’s stance on Bill 5 would be useful.

4. Integrated Resource Planning Discussion
   - Alison Moore discussed Integrated Resource Planning (IRP) and asked what the best way to engage the IWG is going forward and feedback on initial focus for engagement.
   - Daniel Vollmer suggested setting up a smaller group to continue to discuss. The IWG and Enbridge Gas Inc. agreed.

- Kodi Chrisjohn-Deleary asked what Nations were engaged for the Southern Lake Huron Pilot (SLHP) project.
    - Lauren Whitwham confirmed that Chippewas of Kettle and Stoney Point First Nation (CKSPFN) and Aamjiwnaang First Nation (AFN) were engaged. Lauren Whitwham confirmed that they would provide the information provided to date.
- Kodi Chrisjohn-Deleary asked about the SLHP's objective.
    - Alison Moore advised that it was to look at how enhanced targeted energy efficiency and demand response programs impact peak hour flow and demand, and how to best design, deploy and evaluate these programs going forward. The learnings from the pilot would be used to inform the evaluation of non-pipelines alternatives.
- Kodi Chrisjohn-Deleary emphasized the importance of treaty-based engagement.
    - Alison Moore offered to provide the SLHP application that was filed with the OEB.

5. Sustainability and Nature-related Disclosures at Enbridge
    - Gina Jordan presented on Sustainability and Nature-related Disclosures at Enbridge.
    - Rob Lukacs asked what is meant by 'monitoring impacts to wildlife'.
        - Gina Jordan advised that Enbridge Gas Inc. continually monitors performance and does internal audits on protection programs and looks to enhance performance. Gina Jordan confirmed that programs include air and land monitoring.
    - Lisa DeMarco asked about materiality assessments and definitions of nature.
        - Gina Jordan confirmed that Enbridge Gas Inc. performs a materiality assessment on a regular basis and it is in the Sustainability Report. Enbridge Gas Inc. focuses on the global risk to nature loss and its effect on business and society.
        - Gina Jordan also confirmed that they are looking at the Taskforce on Nature-related Financial Disclosures (TNFD) and working to better understand impacts and dependencies. Enbridge Gas Inc. has also started working with Tandem Global to consider this.
    - Lisa DeMarco asked for Tandem Global's Terms of Reference
    - Gina Jorden advised that in terms of TNFD, it is still early days.
        - Lisa DeMarco clarified the point of assessing material risk in terms of impact and dependencies is important to Nations.
    - Lisa DeMarco asked to be provided any materials shared with the Indigenous Advisory Group (IAG) around nature related dependencies and impacts.
    - Gina Jordan advised that they would share the pages in the Sustainability Report that address Lisa DeMarco's questions.
    - Shelley Rahme advised of an opportunity to support grassland birds and habitat similarly to how Enbridge has deployed sheep in Sarnia.
        - Gina confirmed they could look into this once Tandem Global finishes their report.
6. Brattle Recommendations Follow-Up
    - Brent Bullough summarized some of the Brattle Recommendation categories.
    - Related to the RSA, Enbridge Gas Inc. is seeking clarification on several points, which will be confirmed with the IWG via email before the next meeting
    - how the IWG sees the lifecycle impacts being addressed.
        - what scenarios the IWG is interested in.
        - if it was the pathways report versus the RSA.
        - what was meant by upstream and downstream environmental and economic impacts.

- Brent Bullough discussed the recommendation for Enbridge Gas Inc. to increase support for First Nation communities to be self-sufficient and advised that the general response from Enbridge Gas Inc. is that they feel they are doing this through things like capacity funding.
- Brent Bullough discussed how one of the recommendations was to engage Indigenous groups to co-develop impact assessments and publish a timeline for these engagements, but Enbridge Gas Inc. is seeking clarification on what the impact assessments would be on.
- Enbridge Gas Inc. and IWG agreed to discuss further over email.
- Brent Bullough advised that Enbridge Gas Inc. is committed to engaging on energy transition plans and the 2029 submission and sought clarification on what 'major projects' refer to in the recommendations and asked if it is specific to energy transition or projects which is beyond the scope of what Brattle was looking at.
- The IWG agreed to respond to questions over email afterward.

7. Action Items

- Item 1: Enbridge Gas Inc. COTTFN, and IWG to set up a meeting to discuss heat pumps.
- Item 2: Enbridge Gas Inc. to confirm that the final March's minutes were shared with the IWG.
- Item 3: Enbridge Gas Inc. to include Bill 5 on the September IWG meeting agenda.
- Item 4: Enbridge Gas Inc. to inquire about circulating Enbridge Gas Inc's statement on Special Economic Zones Act and Bill 5 with the IWG.
- Item 5: Enbridge Gas Inc. to inquire about circulating a document of Enbridge's lobbying activity regarding Bill 5 with the IWG.
- Item 6: Kate Kempton to circulate the Notice of Application on Bill 5 and the Endangered Species Act to Enbridge Gas Inc. and the IWG.
- Item 7: Lisa DeMarco to follow up with an email outlining the key discrepancies discussed at the meeting to be included in the May minutes. (Item 9 outstanding from May meeting).
- Item 8: Enbridge Gas Inc. to see if they can provide the IAG meeting presentations/ notes to the IWG. (Item 10 outstanding from May meeting).
- Item 9: Enbridge Gas Inc. to provide IWG customer engagement framework for rebasing.
- Item 10: Enbridge Gas Inc. to provide IWG rights holder engagement framework for rebasing.
- Item 11: Enbridge Gas Inc. and IWG to create a sub-committee for RSA discussion.
- Item 12: Enbridge Gas Inc. to provide the invite to Lisa DeMarco and Nicholas Daube for the July 30 RSA technical session.
- Item 13: Enbridge Gas Inc. to investigate changing EA language from 'confirmation of preferred route' to 'determination of preferred route' and from 'Incorporation of Treaty Rights and Indigenous Knowledge' to 'Weave Treaty Rights and Indigenous Knowledge into Mitigation Measure Development'.
- Item 14: Enbridge Gas Inc. to gather information on what level of information goes into a cumulative effects assessment in regards to archaeological assessments.
- Item 15: Enbridge Gas Inc. to inquire about sharing internal archaeology assessment policies with the IWG.
- Item 16: Enbridge Gas Inc. to consider IWG request to work with archeologists to create a cost benefit analysis of LiDAR along the full preferred route.
- Item 17: IWG to provide list of preferred archeology firms.

- Item 18: IWG and Enbridge Gas Inc. to discuss having a focused discussion on archaeological expertise related to community knowledge.
- Item 19: Enbridge Gas Inc. to inquire if language of 'resources' in the Environmental process presentation could be changed to 'assets' when speaking to archaeological resources.
- Item 20: Enbridge Gas Inc. and IWG to create a smaller group to discuss IRP and triangulate topics to discuss.
- Item 21: Enbridge Gas Inc. to share the information shared with CKSPFN and AFN about the SLHP project.
- Item 22: Enbridge Gas Inc. to provide the SLHP application that was filed with the OEB to the IWG.
- Item 23: Enbridge Gas Inc. to provide key pages in the Sustainability Report that discuss impacts and dependencies.
- Item 24: Enbridge Gas Inc. and IWG to further discuss the Brattle Recommendations over email.
- Item 25: Enbridge Gas Inc. to provide the slides from today's meeting.

NEXT MEETING

Next meeting of the IWG is set to take place at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8 on September 23, 2025. Team to canvas for an Agenda closer to the date.

APPENDIX A – AGENDA FOR MEETING OF IWG ON JULY 15, 2025

Time	Matter	Participants
9:00-9:10 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Lauren Whitwham and Group
9:10-9:35 am	Engagement Opportunities/ Timelines – 2029 Filing and Projects	Vanessa Innis and Group
9:35-10:00 am	Regional Scenario Analysis – Engagement Approach	Cara-Lynne Wade and Group
10:00-10:45 am	Enbridge Updated LTC Environmental Assessment Process	Kelsey Mills and Group
10:45-11:15 am	Brattle Recommendations Follow-Up	Brent Bullough and Group
11:15-11:30 am	Integrated Resource Planning Discussion	Alison Moore and Group
11:30-12:00 am	Sustainability and Nature-Related Disclosures at Enbridge	Gina Jordan and Group
12:00 pm	Wrap-up/ Adjourn	Group

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held on **September 23, 2025,** at 10:00 a.m. at Enbridge Gas Inc., 500 Consumers Road, North York, Ontario M2J 1P8.

PRESENT

Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Todd Jardine	Three Fires Group
Rick Peters	Three Fires Group
Kate Kempton	Woodward and Company, Ginoogaming First Nation
Nicholas Daube	Woodward and Company, Ginoogaming First Nation
Shelly Rahme	Ginoogaming First Nation
Kodi Chrisjohn-Deleary	Chippewas of the Thames First Nation
Jennifer Mills	Chippewas of the Thames First Nation
Peter Fraser	The Brattle Group
Diana Audino	Enbridge Gas Inc.
Richard Brant	Enbridge Gas Inc.
Jennifer Murphy	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Matthew Webster	Enbridge Gas Inc.
Kris Geekie	Enbridge Gas Inc.
Jessica Maga	Enbridge Gas Inc.

Note on usage of "Enbridge Inc" and "Enbridge Gas Inc": Policies and plans, such as the Indigenous Reconciliation Action Plan are Enbridge Inc. documents that apply to the whole company including Enbridge Gas Inc. For the purposes of IWG meetings, Enbridge Inc. (and its affiliates) staff are representing Enbridge Gas Inc.

MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
    - Brent Bullough chaired the meeting.
    - Lauren Whitwham provided a safety moment.
    - IWG approved May meeting minutes.
    - IWG approved July meeting minutes.
    - Status of July meeting action items:
        - Item 1: Brent Bullough confirmed Enbridge Gas Inc. would set up a meeting to discuss heat pumps with Chippewas of the Thames First Nation (COTTFN) and IWG.
        - Item 2: Brent Bullough confirmed the final March meeting minutes were distributed and redistributed them on September 22, 2025.
        - Item 3: Brent Bullough advised that Jessica Maga would be attending to discuss Bill 5.
        - Item 4 & 5: Brent Bullough circulated Enbridge Gas Inc.'s statement on Special Economic Zones Act and Bill 5 along with information of Enbridge Gas Inc.'s lobbying activity with the IWG on August 7, 2025, and advised that Jessica Maga could also speak to this.
        - Item 6: Kate Kempton and Nicholas Daube provided the Notice of Application on Bill 5 and the Endangered Species Act to Enbridge Gas Inc. and the IWG on July 15, 2025.
        - Item 7: IWG approved May meeting minutes.
        - Item 8: Brent Bullough advised that Enbridge Gas Inc. is unable to share Indigenous Advisory Group (IAG) meeting presentations/ notes.
        - Item 9: Brent Bullough provided the Customer Engagement Framework for rebasing on September 23, 2025.
        - Item 10: Brent Bullough advised that Enbridge Gas Inc. generally includes the Indigenous Peoples Policy (IPP) as part of the application and Enbridge Gas Inc. but will consider whether a Rights-Holder Engagement Framework for rebasing would be beneficial after receiving and reviewing comments from the IWG on the Customer Engagement Framework.
        - Item 11: Brent Bullough confirmed a Regional Scenario Analysis (RSA) sub-committee was created and a meeting took place on September 3, 2025, with IWG members in attendance.
        - Item 12: Brent Bullough provided the RSA technical session invitation to Lisa DeMarco and Nicholas Daube.
        - Items 13, 14, 15, 16, 18, and 19: Deferred until next meeting.
        - Item 17: Nicholas Daube provided a list of archaeology firms and one was added during discussion. There is no consensus at this time on the firms. Further discussion needed by IWG members on recommended firms and Enbridge Gas Inc. to consider how recommended firms can be integrated into its policies and procedures.
        - Item 20: Brent Bullough advised that Enbridge Gas Inc. sought interest on discussing IRP on August 15, 2025, requesting input by September 29, 2025.
        - Items 21 & 22: Brent Bullough shared the Southern Lake Huron Pilot project information and application filed with the Ontario Energy Board (OEB) on August 15, 2025.

- Item 23: Brent Bullough confirmed key pages in the Sustainability Report were provided and would confirm the date.
- Item 24: Brent Bullough advised that Enbridge Gas Inc. hadn't received anything regarding the Brattle Recommendations via email. Rob Lukacs to provide IWG responses.
- Item 25: Brent Bullough provided July meeting slides and the IAG organization chart on September 22, 2025.

2. IWG Suggested Archaeology Firms
   - Nicholas Daube presented potential archaeology firms, emphasizing that group consensus needs to be obtained and part of a broader conversation.
     - Potential firms:
       - White Spruce Archaeology
       - Tamarack
       - TMHC Inc.
       - Archaeological Research Associates (ARA)
   - Rob Lukacs advised that Mississaugas of Scugog Island First Nation (MSIFN) would also like to add Northeastern Archaeological Associates as a firm to consider.
   - Lauren Whitwham advised that Enbridge Gas Inc. works with TMHC Inc. already.
   - Jennifer Mills advised that she likes the fact that contracts for archaeological work have been with Enbridge Gas Inc. instead of the actual firms as it alleviates some of the administrative work.
   - Nicholas Daube suggested setting up a process to discuss any constructive feedback a participant may have about a firm.
     - Nicholas Daube advised that any endorsement from First Nations should include how they would like to see firms integrated into the process.
   - Nicholas Daube asked Enbridge Gas Inc. how they could use the list.
   - Rob Lukacs emphasized support for the list Nicholas Daube provided and noted that it would be good to hear from Enbridge Gas Inc. on its thoughts on the list.
   - Daniel Vollmer agreed and emphasized that the list is not necessarily a consensus among IWG members.
   - Daniel Vollmer advised that it is important to ask the Nations that are impacted their thoughts on the firms.
   - Kodi Chrisjohn-Deleary advised that the firms put forward by First Nations are based on relationships that are valued, which is related to Bill 5 and Special Economic Zones.
     - Kate Kempton agreed.
   - Nicholas Daube summarized the discussion and suggested continuing the conversation at the next meeting.
   - Kelsey Mills agreed that Enbridge Gas Inc. could investigate the list and how the suggestions could be incorporated into existing policies and procedures.
3. EGI Relationship with TC Energy
   - Kate Kempton discussed her client's relationships with TC Energy, as well as a claim that has been filed by Ginoogaming First Nation (GFN) against TC Energy. Her comments included:
     - Advised that they are not involved in an Indigenous working group with TC Energy and have been trying to get them to change this fact.
       - Launched a lawsuit in 2017 regarding integrity digs that is still ongoing.

- Advised that TC Energy pays Crown governments and suggested that they pay First Nation governments similar payments (i.e., in the form of a property tax).
- Suggested Enbridge Gas Inc. and the IWG go to the Canada Energy Regulator (CER) together to include this in the rate base as TC Energy has refused.
- Noted that TC Energy was also asked to participate in the tolls taskforce and TC Energy also declined.
- Emphasized the importance of First Nations being at the table to create a process of equity.
- Advised that they were informing Enbridge Gas Inc. of this because they do business with TC Energy.
- Asked Enbridge Gas Inc. to meet with TC Energy to persuade them to open the tolls taskforce.
- Would like TC Energy to negotiate with First Nations the way they had offered to.
- Appealed to Enbridge Gas Inc.'s corporate sense through the IWG to discuss with TC Energy and report back on the discussions.

- Diana Audino confirmed her understanding of Kate Kempton's position and emphasized that Enbridge Gas Inc. and TC Energy are different companies. Diana Audino advised that she would follow-up with her contact at TC Energy to explore.
  - Diana Audino advised that there are challenges on the property tax side, and Kate Kempton clarified that it didn't have to be a property tax specifically, but just a payment for using the land.
    - Shelly Rahme asked how Enbridge Gas Inc. would do this.
      - Diana Audino advised that they she would reach out to see who Enbridge could talk to at TC Energy about the matter.
      - Kate Kempton emphasized that they want Enbridge Gas Inc. to pressure TC Energy on the premise that what's being done for the Crown government should be for First Nations.
- Nicholas Daube advised that one point of dispute is the ongoing impact of TC Energy's operations.
- Nicholas Daube raised concerns about what Enbridge Gas Inc. is doing to ensure their business partners are acting appropriately
- Nicholas Daube suggested that First Nations would like to be meaningfully consulted about the issues that form the basis of EGI's applications. They would like these consultations also to take place in a timely manner. He suggested that consultations could take place in a way that allows the IWG to flag concerns and opportunities, suggesting it would be constructive to find a way to do this. He also acknowledged that EGI and the IWG would likely need to find a way to ensure that the integrity of EGI's litigation process and the integrity of OEB's process is appropriately respected, but he was suggesting that the IWG should be able to find a way to navigate these various priorities.

4. Enbridge and Bill 5
   - Jessica Maga attended to answer questions on Bill 5.
   - Kate Kempton discussed her position on how Bill 5 and C5 constitute erasure of First Nations and the work done towards reconciliation. Kate Kempton advised that her client wants Enbridge Gas Inc. to stand with the First Nations against these bills. Kate Kempton made these additional comments:
     - Defined reconciliation as the coexistence of two or more systems or worldviews so that they are mutually respectful. Reconciliation is to enable respectful space for First Nations to

govern, have worldviews, conduct ways of life, societies, that isn't forced to conform to or be subjected to other ways.
    - Emphasized that these bills are not a reaction to the United States and are based on Henry VIII regime of cabinet privilege.
    - Stated that the bills are fundamentally wrong and severe harm is being done.
- Nicholas Daube asked if Enbridge Gas Inc. had engaged on any questions relating to Bill 5 and C5 affecting First Nations.
    - With regards to Bill 5 specifically, Jessica Maga advised that Enbridge Gas Inc. did submit consultation vis a vis the public Environmental Registry of Ontario and there were conversations in terms of procurement, an ongoing concern about cost to ratepayers, and making sure the rate base is getting good value.
    - Nicholas Daube observed that Enbridge Gas Inc. did not address in its submissions in any significant way the question of how the legislation impacted First Nations.
        - Jessica Maga advised that the thrust of Enbridge Gas Inc.'s consultation had been that if the government is interested in developing economic zones, energy must be a part of the conversation.
        - Jessica Maga advised that Enbridge Gas Inc. also commented on the idea of one project, one permit and that engaging Indigenous communities is important.
        - Jessica Maga advised that the questions from the Bill 5 public engagement were not specific to what Enbridge Gas Inc. thinks about Indigenous communities. Enbridge Gas Inc. also discussed integrated planning and the importance of Indigenous engagement in the integrated energy plan.
        - Nicholas Daube, on behalf of GFN, advised that they were available as resources for Bill 5 and C5 if Enbridge Gas Inc. is looking for additional considerations.
- Nicholas Daube discussed the two aspects of Bill 5:
    - Special Economic Zones
        - Scary to First Nations who want to see protection continue and want to see the ability to share in decision making processes.
    - Concerns with specific legislation
        - Ontario is legislating away oversight, monitoring and ongoing protection.
        - Legal question on whether this is honorable or dishonorable conduct.
        - Whether Ontario is concerned with increasing the likelihood of Indigenous participation or if they have given up.
- Rob Lukacs sought clarification on what Nicholas Daube had advised that GFN requested.
    - Nicholas Daube advised that GFN would like to see perspectives captured in how Enbridge Gas Inc. thinks about Bill 5 and suggested the IWG be used as a resource at earlier stages.
- Rob Lukacs asked for clarification on the point Nicholas Daube had made about the cost of capital.
    - Nicholas Daube advised that the difference between how the BC regulator and the Ontario regulator approach cost of capital is the BC regulator thinks about risk (i.e. What is the risk of Indigenous opposition)
- Rob Lukacs asked if Enbridge Gas Inc. covers Indigenous consultation and accommodation expenses through its cost of capital filings at the OEB.
    - Tania Parsad confirmed that for LTC, the capacity and funding are involved in the project budget (not cost of capital, but capital expense)

- Rob Lukacs asked if Enbridge Gas Inc. would support explicitly recognizing accommodation costs as recuperable capital costs, not just as operating costs.
    - Tania Parsad advised that if it's related to a capital project, it's a capital expense, and if it's an operating type of activity, it's an operating expense.
    - Rob Lukacs sought clarification on when Enbridge Gas Inc. would apply the explicit recognition of accommodation costs as recoverable capital costs through a filing to the OEB.
        - Tania Parsad advised that the costs would be part of the capital cost of the project.
        - Lauren Whitwham advised that for LTC projects, capacity funding is in the project budget.
- Rob Lukacs advised that this is related to Bill 5 and the streamlining of approvals and would ideally like to see this embedded in submissions to the OEB to have accommodations covered when determining cost of capital so First Nations could be guaranteed accommodations coming out of capital projects.
    - Tania Parsad advised that Enbridge Gas Inc. does itemize this and is transparent about what the costs are, and this information is provided in filings.
        - Rob Lukacs advised that they are seeking to have the accommodation costs still covered.
        - Lauren Whitwham responded that in engagement, Enbridge Gas Inc. could still work with First Nations regarding mitigation measures, accommodation, and would still provide capacity funding.
            - Rob Lukacs asked if the permitting is removed through Bill 5, how would that be taken into account through the filing with the OEB.
            - Tania Parsad suggested this be a meeting takeaway.
            - Nicholas Daube offered to talk to Rob Lukacs offline.
- Jennifer Mills asked if there is a document that Enbridge Gas Inc. uses to determine the parameters of accommodation.
    - Lauren Whitwham responded that the Hydrocarbon Pipeline guidelines direct mitigation measures.
    - Diana Audino advised that Indigenous consultation requirements are also in the guidelines.
- Rob Lukacs advised that those costs only consider accommodations identified through the consultation period.
    - Diana Audino responded that it then turns into an ongoing operation expense.
        - Tania Parsad advised that Enbridge Gas Inc. follows accounting rules on whether it is a capital or operating cost.
            - Rob Lukacs asked where these rules are.
                - Tania Parsad answered that they are the Generally Accepted Accounting Principles (GAAP) or International Financial Reporting Standards (IFRS).

5. Brattle Recommendations – IWG Clarification
    - Rob Lukacs advised that they were still working through the recommendations.
6. Regional Scenario Analysis Update – Engagement Outcomes
    - Jennifer Murphy provided an update on the RSA session on September 3, 2025, and advised that Enbridge Gas Inc. is working on putting together a summary of the feedback.

7. Wrap-up
   - Nicholas Daube offered a summary of the meetings action items.
   - Nicholas Daube advised that GFN are anticipating that they would say that there should be earlier engagement with the IWG and First Nations regarding a 5-year plan.
     - Lauren Whitwham suggested this is an opportunity to tell the OEB that this should happen and GFN should include this in their reply.
     - Nick Daube asked if there was a way to get feedback to the OEB soon.
       - Lauren Whitwham replied that Enbridge Gas Inc. is moving in this direction.
       - Nicholas Daube suggested they keep talking about the 5-year plan.
       - Tania Parsad further suggested starting by following the OEB guidelines and agreed that it was worth revisiting.

Action Items

1. Enbridge Gas Inc., COTTFN, and IWG to set up a meeting to discuss heat pumps.
2. Rob Lukacs to provide IWG responses to Enbridge Gas Inc. questions on the Brattle recommendations.
3. (deferred item 13): Enbridge Gas Inc. to investigate changing environmental assessment (EA) language from 'confirmation of preferred route' to 'determination of preferred route' and from 'Incorporation of Treaty Rights and Indigenous Knowledge' to 'Weave Treaty Rights and Indigenous Knowledge into Mitigation Measure Development'. (Item 13 outstanding from July meeting).
4. (deferred item 14): Enbridge Gas Inc. to gather information on what level of information goes into a cumulative effects assessment regarding archaeological assessments. (Item 14 outstanding from July meeting).
5. (deferred item 15): Enbridge Gas Inc. to inquire about sharing internal archaeology assessment policies with the IWG. (Item 15 outstanding from July meeting).
6. (deferred item 16): Enbridge Gas Inc. to consider IWG request to work with archeologists to create a cost benefit analysis of LiDAR along the full preferred route. (Item 16 outstanding from July meeting).
7. (deferred item 19): Enbridge Gas Inc. to inquire if language of 'resources' in the Environmental process presentation could be changed to 'assets' when speaking to archaeological resources. (Item 19 outstanding from July meeting).
8. IWG to provide input on IRP. (Item 20 outstanding from July meeting).
9. Enbridge Gas Inc. to confirm the date the Sustainability Report key pages were provided to the IWG.
10. (deferred item 18): Enbridge Gas Inc. and IWG to continue archaeology firm discussion at the next meeting.
11. (deferred item 18): Enbridge Gas Inc. to investigate provided archaeology firms and see how they could be incorporated into policies and procedures.
12. Enbridge Gas Inc. to reach out to TC Energy to see if anything can be done to resolve challenges and report back to the IWG.
13. Enbridge Gas Inc. to consider how accommodation costs would be considered if permitting is removed through Bill 5.
14. Enbridge Gas Inc. to circulate dates for November meeting.

NEXT MEETING

Next meeting of the IWG is tentatively set to take place at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8 in November. Team to canvas for an Agenda closer to the date.

APPENDIX A – AGENDA FOR MEETING OF IWG ON SEPTEMBER 23, 2025

Time	Matter	Participants
10:00-10:20 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Lauren Whitwham and Group
10:20-10:50 am	EGI Relationship with TC Energy	Kate Kempton and Group
10:50-11:10	IWG Suggested Archaeology Firms	Nicholas Daube and Group
11:10-11:25	Enbridge and Bill 5	Jessica Maga and Group
11:25-11:45	Brattle Recommendations – IWG Clarification	IWG and Group
11:45-12:30	Lunch	
12:30-1:00	Regional Scenario Analysis Update – Engagement Outcomes	Cara-Lynne Wade and Group
1:00-1:15 am	Wrap-up/Adjourn	Group

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held virtually on **November 26, 2025**, at 9:00 a.m.

PRESENT

Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Todd Jardine	Three Fires Group
Rick Peters	Three Fires Group
Tracy Skye	Six Nations Natural Gas
Nicholas Daube	Woodward and Company, Ginoogaming First Nation (GFN)
Diana Audino	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Arend Wakeford	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Gesiena Antuma	Enbridge Gas Inc.
Alvaro Atencio	Enbridge Gas Inc.
Jessica Maga	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Henry Ren	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Erin Lindsay	Enbridge Gas Inc.
Matthew Webster	Enbridge Gas Inc.

Note on usage of "Enbridge Inc." and "Enbridge Gas Inc.": Policies and plans, such as the Indigenous Reconciliation Action Plan are Enbridge Inc. documents that apply to the whole company including Enbridge Gas Inc. For the purposes of IWG meetings, Enbridge staff are representing Enbridge Gas Inc.

MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
    - Brent Bullough chaired the meeting and provided a safety moment.
    - Brent Bullough requested invoices for work completed relating to IWG be submitted by December 7, 2025.
    - Enbridge Gas Inc. and the IWG tentatively approved minutes from the September 2025 meeting, subject to confirmation from Nicholas Daube that his submitted edits were captured correctly.
    - Brent Bullough suggested removing the Integrated Resource Plan (IRP) as a standing agenda item and would request them to join if needed in the future. The IWG agreed.
    - Rob Lukacs requested Enbridge Gas Inc.'s self-assessed Oil and Gas Methane Partnership 2.0 (OGMP) maturity level for venting, fugitive emissions, flaring and stationary combustion be added as an agenda topic to a future meeting. He further requested a discussion be held at a future meeting to develop a plan to communicate rate harmonizations to Indigenous nations.
        - These items will be on an early 2026 meeting agenda.
    - Brent Bullough advised that the IWG would discuss preferred archaeology firms for archaeology work for Enbridge Gas Inc. projects at a 2026 meeting.
    - Brent Bullough advised that the gas supply team for Enbridge Gas Inc. would be presenting at the first IWG meeting in 2026.
        - Nicholas Daube asked if this was the gas supply team's annual update.
            - Lauren Whitwham advised that Enbridge Gas Inc. had committed to presenting an annual update.
    - Rob Lukacs advised that the Brattle recommendation discussion would take place at an early 2026 meeting.
    - Nicholas Daube asked to add a discussion about meeting location and experts to today's meeting agenda.
    - Status of IWG September 2025 meeting action items:
        - Item 1 and 2: Brent Bullough confirmed that the IWG had discussed it earlier in the meeting.
        - Items 3-7: Enbridge Gas Inc. and IWG agreed to defer environmental items to a future meeting.
        - Item 8: Brent Bullough confirmed that the IWG had discussed it earlier in the meeting.
        - Item 9: Brent Bullough to confirm the date the Sustainability Report key pages were provided to the IWG.
        - Item 10 and 11: Enbridge Gas Inc. and IWG agreed to defer archaeology items to a future meeting.
2. IWG Relationship with TC Energy
    - Diana Audino provided an update on her discussion with TC Energy (Item 12 from September meeting) and answers to Kate Kempton's questions.
        - Would the tolls task force be open to First Nations?
            - First Nations cannot be on the tolls task force because they are not shippers on TC Energy's system, which is a requirement to be part of the tolls task force.

- Whether TC Energy would negotiate an Indigenous property tax/ some sort of mechanism.
  - Advised that this is a confidential TC Energy matter.
- Nicholas Daube didn't identify specific questions but noted that this is a serious issue for GFN and one that is not going away.
  - Nicholas Daube advised he would take this back to GFN and noted it is important for Enbridge Gas Inc. to know that GFN is increasingly looking for help in the matter.

3. 2027 + Demand Side Management Plan (DSM Plan)

- Erin Lindsay provided a comprehensive update on the approved 2026 DSM Plan and the upcoming 2027+ application, detailing program continuity, budget allocations, and anticipated procedural steps.
- The 2026 Plan has been approved as proposed.
- The OEB requested Enbridge Gas Inc. provide an update on what they anticipate happening with the multi-year DSM Plan and when that would be submitted. Enbridge Gas Inc. anticipates filing a 2027+ DSM Plan by the end of this year.
- Engagement when developing a DSM Plan (specifically Indigenous engagement):
  - From a delivery model perspective and how to tailor outreach in a collaborative format, Enbridge Gas Inc. relied on First Nation Engineering Services Ltd. (FNESL), industry organizations, and Enbridge Gas Inc.'s Community and Indigenous Engagement (CIE) team for suggestions and feedback.
  - There is flexibility to introduce measures, change incentives, and change the delivery model within the construct of a DSM Plan.
  - Have had success with Indigenous communities, including hosting community events.
  - From the technical measures to offer, Enbridge Gas Inc. relied on FNESL, delivery agents and contractors looking to understand best practices, potential opportunities, etc.
- Programs targeting First Nation customers or where we would expect First Nation customers to participate are the Home Winterproofing Program (HWP) and/or the Residential Home Renovation Savings (HRS) Program.
- Home Winterproofing Program (HWP)
  - Most relevant program to First Nation customers; preferred path for those households that qualify.
  - Involves providing home insulation, among other items, at no cost to customers, and includes a budget to help overcome challenges that might prevent participation.
  - Nicholas Daube requested elaboration on the consultation done with First Nations.
    - Lauren Whitwham confirmed engagement with Chippewas of Kettle and Stony Point (CKSPFN) and Mohawks of the Bay of Quinte (MBQ).
    - It was noted though that there have been some barriers to bringing the HWP to First Nation communities. There is a team member who is Indigenous who is advancing the program in First Nations' communities. Enbridge Gas Inc. is also working with an organization out of the Chippewas of Rama First Nation (CRFN) to determine whether any improvements could be made to make it more feasible for Indigenous communities' participation. Enbridge Gas Inc. had reached out to four nations to advance the program; Saugeen First Nation, CKSPFN, MBQ and Couchiching First

Nation. The program has been going on for years and Enbridge Gas Inc. has worked with almost every nation that's involved in gas distribution. Enbridge Gas Inc. has tried to bring it to GFN and Nipissing First Nation (NFN) but have had challenges with uptake. Enbridge Gas Inc. had a community event at MBQ to discuss the program and have people sign up to try and move it forward.

- Nicholas Daube noted his client is interested in learning what GFN can be advocating for in proceedings and what generally has worked for the community.
- Lauren Whitwham advised that the program is only available to Enbridge Gas Inc. customers in the community due to the funding structure.
    - This is a challenge because Enbridge Gas Inc. may only service some homes in a community and therefore only these homes would be eligible.
- Erin Lindsay advised that they are targeting at least four nations per year and rely on FNESL to reach out to the Band Council.
    - Lauren Whitwham advised that the CIE team is also included in this initial engagement with FNESL.
- Erin Lindsay emphasized that Enbridge Gas Inc. is looking for any opportunity to build awareness among Indigenous communities.

- Residential HRS Program
    - This is the jointly delivered program between Enbridge Gas and the IESO.
    - Launched January 2025, it is open to residential consumers across Ontario providing access to all available rebates/incentives available for energy efficiency by either Enbridge Gas or the IESO.
    - Enbridge Gas is the natural gas component of the program and Enbridge Gas customers would be eligible for natural gas DSM incentives.
    - Enbridge Gas will be proposing continuation of this program, expected to be filed by the end of the year.
- Daniel Vollmer asked if there were Indigenous participants in the stakeholder advisory group.
    - Erin Linday advised that the OEB decided on who would be part of the advisory group and none were Indigenous.
    - Daniel Vollmer asked if intervenor groups that were involved in the consultation were Indigenous.
        - Erin Lindsay responded that invitations were based on the last proceeding and Anwaatin Inc. was invited but she didn't think they attended.
    - Daniel Vollmer asked if there was a possibility for the IWG to continue to be updated on programs and included in the process.
        - Erin Lindsay responded that they participated in the IWG to seek feedback and can continue to do so since there is flexibility in the plan's execution.
        - Lauren Whitwham advised that once they receive feedback, the HWP team discussed presenting to the IWG.
    - Daniel Vollmer asked if there is data on the HWP's uptake in First Nations.
        - Lauren Whitwham answered that there is basic data that they could get from the team and noted the program experienced less uptake than hoped.
- Nicholas Daube sought clarification on the barriers to program uptake noting he heard the following factors:
    - Knowledge in the community.

- General community buy-in.
- Suitability of buildings.
    - Lauren Whitwham clarified that “barriers” may not be the right word and added that the following may limit participation:
        - Proof of income is needed from the resident, so Enbridge Gas is trying to remove this requirement.
        - Factor of trust/ education of the program needed.
        - Some homes don’t qualify because they need improvements to be eligible.
- Nicholas Daube asked if approvals are needed to remove the income question.
    - Erin Lindsay advised that in the past they’ve submitted a letter to the OEB (there are options).
- Nicholas Daube asked if there is a way to document how initiatives effect First Nations, wondering why there is no discussion about implications for First Nations, even indicating that it seemed Enbridge Gas would like to do more but there are barriers standing in the way.
        - What sort of policy support might make it easier for Enbridge Gas to advance DSM programming in First Nation communities.
        - Whether Enbridge Gas is anticipating a discussion in future DSM submissions and how they relate to First Nations.
    - Lauren Whitwham suggested that another factor is that Nations have a lot of other engagement going on.
        - Need to work with communities to lessen administrative burden and find ways to support communities.
    - Nicholas Daube advised that GFN would support a general discussion as a standard practice about implications for First Nations and an elaboration on barriers to doing more.
    - Erin Lindsay noted there's discussion about activities impacting First Nations in the annual report.
    - Nicholas Daube suggested the energy sector treats relationships with First Nations as being limited to the DTC being satisfied. GFN's position is that this is at odds with reconciliation and the Ontario government’s statements about First Nation partnerships.

- Rob Lukacs asked how Enbridge Gas is measuring and reporting on supply chain within the DSM program (i.e. specific indicators to demonstrate real market transformation rather than just program delivery).
    - Erin Lindsay advised that there aren't specific metrics related to the number of contractors or changes in equipment. There are currently no separate market transformation metrics because it's seen as embedded in the process (e.g., upgrades in homes are fully customized) - no specific metrics or KPI on this.
- Rob Lukacs asked if there are supply chain bottle necks (e.g., workforce, contractor capacity, product availability) slowing down adoption so Enbridge Gas can go beyond just issuing rebates.
    - Lauren Whitwham advised that they don’t track metrics but have FNESL in the community working to implement the program.
        - Erin Lindsay added that it depends on the program, but supply chain is not an issue with the HWP delivered to Nations.

- Rob Lukacs asked for elaboration on the tools used to influence peak management to reduce/ reshape natural gas demand. He was seeking to understand what's being done to further DSM.
    - Erin Lindsay advised that they define DSM as energy efficiency and are not looking at peak management.
    - Rob Lukacs asked why only downstream efficiencies are being considered while Enbridge Gas Inc. has upstream efficiencies that could have improvements.
        - Erin Lindsay advised there are programs doing similar things such as the IRP Sarnia pilot.
        - Lauren Whitwham added Enbridge Gas also works with large industrial partners to try and reduce their use of natural gas; however, Erin Lindsay and her team work on efficiency improvements.
        - Lauren Whitwham also clarified that Enbridge Gas transports natural gas and has no upstream activities in Ontario to consider.
- Rob Lukacs asked if the IWG could speak to someone from DSM to better understand how Enbridge Gas is working with its municipal and industrial partners to maximize efficiencies on DSM.
    - Erin Lindsay advised that depending on the sector, there are various programs, including retrofit and new construction. Enbridge Gas's full DSM portfolio is described in its DSM Annual Reports and filed DSM Plans.

4. 2029 Rebasing Engagement
    - Gesiena Antuma presented on 2029 rebasing and engagement with customers which is currently in the planning process.
    - Multiple stakeholder sessions are planned with the first one on December 4, 2025.
    - Enbridge Gas is seeking input from the IWG on the best way to conduct engagement with Indigenous customers.
        - Nicholas Daube asked why 2029 and Gesiena Antuma responded that the rates start for the plan in 2029, pointing out that the last rebasing was for 2024, but engagement commenced in 2021 and 2022. The goal is to submit the application in September 2027.
        - Nicholas Daube indicated that from the perspective of some of the Nations represented on the IWG, the last rebasing application didn't do enough to address concerns.
    - Nicholas Daube continued that IWG members had offline discussion and determined the need for an expert to help channel First Nations perspectives, needs, and opportunities into a professional framework that the OEB requires. The IWG requests the following:
        - Retain an expert to deliver a slide deck that would be presented to the IWG and serve as a basis for discussion.
        - Timing is good in terms of where Enbridge Gas is in the process and the IWG is hopeful to have the expert early in the new year.
        - IWG could provide preliminary ideas, but further comment would come in the form of a professional presentation and hearing from the Nations themselves.
            - Gesiena Antuma asked if the presentation would be for ideas on how to conduct the engagement or if it would cover customer needs and preferences.
                - Nicholas Daube clarified that the expert would focus on the process. Previous customer engagement survey was limited to a question about

Indigenous self-identification and didn't go into what potential concerns were.
- Under this proposal, specific concerns would come from the First Nations themselves.

- Rick Peters asked if the survey was the primary form of engagement previously and what else could be done.
  - Gesiena Antuma confirmed and advised that more can be done for customer engagement.
  - Nicholas Daube referred to a previous point made by Kodi Deleary that the new community energy representative would have information that a survey wouldn't be able to collect.
  - Rick Peters advised that they are also looking to revise their community energy plan and input gathered through that process could also contribute to DSM discussions.
- Rick Peters and Nicholas Daube are to connect on this matter.

- Jessica Maga asked if the expert would be for the whole rebasing process or just the engagement piece?
  - Nicholas Daube advised they hadn't drafted the scope of work but would focus on aspects connected to the IWG's purpose.
  - Gesiena Antuma noted that the goal is to have all the customer engagement completed by November 2026 so timing is important.
    - Nicholas Daube acknowledged the timing and noted the need to retain the expert soon.

5. Update on Experts
   - Nicholas Daube provided an update on retaining an expert to present on possible different rates for Indigenous and non-Indigenous customers.
     - Similar approach as with Brattle by providing the IWG with a PowerPoint report.
   - Nicholas Daube invited any questions/ input from IWG members.
6. Potential Meeting Locations
   - IWG agreed to have the next meeting in person at the Enbridge Gas London office in mid to late February 2026.

Action Items

1. Enbridge Gas Inc. to confirm the date the Sustainability Report key pages were provided to the IWG.
2. Enbridge Gas Inc. to get data on uptake of HWP.
3. IWG to provide a proposal to retain expert to present engagement recommendations to Enbridge Gas and IWG and another to present on Indigenous rates.

NEXT MEETING

Next meeting of the IWG is set to take place at the Enbridge Gas Inc. office at 109 Commissioners Road London, Ontario N6J 1X7 in February 2026. Team to canvas for an Agenda closer to the date and include previously suggested items.

APPENDIX A – AGENDA FOR VIRTUAL MEETING OF IWG ON NOVEMBER 26, 2025

Time	Matter	Participants
9:00-9:20 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Brent Bullough and Group
9:20-9:30 am	IWG Relationship with TC Energy	Diana Audino and Group
9:30-10:15 am	2027+ DSM Plan	Erin Lindsay and Group
10:15-11:00	2029 Rebasing Engagement	Gesiena Antuma and Group
11:00-11:15 pm	Wrap-up/Adjourn	Group

Enbridge Gas Inc. Indigenous Working Group Minutes

Minutes of a meeting of the Indigenous Work Group (IWG) held on **March 25, 2026**, at 9:00 a.m. at Enbridge Gas Inc., 109 Commissioners Rd, London, Ontario N6J 1X7.

PRESENT

Daniel Vollmer	Resilient LLP, Three Fires Group, Minogi Corp
Rob Lukacs	Minogi Corp.
Emily Ferguson	Minogi Corp.
Todd Jardine	Three Fires Group
Rick Peters	Three Fires Group
Nicholas Daube	Woodward and Company, counsel for Ginoogaming First Nation (GFN)
Zack Hamm	GFN
Jennifer Mills	Chippewas of the Thames
Erna LeClaire	Chippewas of the Thames
Peter Fraser	The Brattle Group
Sarah Welch	Oakview Advisory
Steve Dantzer	Enbridge Gas Inc.
Amy Mikhaila	Enbridge Gas Inc.
Diana Audino	Enbridge Gas Inc.
Tania Persad	Enbridge Gas Inc.
Lauren Whitwham	Enbridge Gas Inc.
Arend Wakeford	Enbridge Gas Inc.
Brent Bullough	Enbridge Gas Inc.
Gesiena Antuma	Enbridge Gas Inc.
Jessica Maga	Enbridge Gas Inc.
Gabby Lapalme	Enbridge Gas Inc.
Kelsey Mills	Enbridge Gas Inc.
Richard Lanni	Enbridge Gas Inc.
Matthew Webster	Enbridge Gas Inc.
Adam Stiers	Enbridge Gas Inc.
Echo Xu	Enbridge Gas Inc.
Richard Wathy	Enbridge Gas Inc.
Johanna Sanchez-Gomez	Enbridge Gas Inc.
Laura Sheehan	Enbridge Gas Inc.
Stephanie Muller	Enbridge Gas Inc.

Tami Showers	Enbridge Gas Inc.
Luna Munro	Enbridge Gas Inc.
Peter Mussio	Enbridge Gas Inc.

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MATTERS FOR DISCUSSION

1. Review of the Agenda for today (attached at Appendix A) and Logistics
   - Brent Bullough chaired the meeting.
   - Tami Showers provided a safety moment.
   - Enbridge Gas Inc. and the IWG approved minutes from the November 2025 meeting.
   - Status of IWG November 2025 meeting action items:
     - Item 2: Brent Bullough advised that an update on the HWP had been moved to the next meeting.
     - Item 3: Brent Bullough advised that a discussion on rate harmonization had been moved to the next meeting.

2. Gas Supply Plan Update
   - Echo Xu presented an overview of Enbridge Gas Inc.'s Gas Supply Plan (the Plan), including in the context of its planning processes and the Ontario Energy Board's Framework.
   - Echo Xu noted that Enbridge Gas Inc.'s first annual update to the five-year Plan was filed on March 3, 2026, which informed the presentation.
   - Nicholas Daube advised that his client GFN believed that GFN's interests could be better accounted for in the Plan, including by way of a better mechanism to incorporate GFN's input. He also raised concerns with TC Energy's operations (which provide gas to Enbridge Gas Inc.) within GFN's Territory.
     - Adam Stiers advised that they see the IWG helping support engagement long term.
     - Enbridge Gas Inc. advised that the IWG provides an opportunity for the First Nation participants to provide input into the Plan going forward and confirmed that we are waiting for the OEB's decision on the public policy considerations of the Plan.
   - Amy Mikhaila advised that regarding TC Energy, there are very few alternatives (if any) for Enbridge Gas Inc. to contract with.
   - Nicholas Daube noted GFN would like different supply scenarios contemplated in an application for the Plan.
   - Nicholas Daube explained that GFN would like to better understand potential impacts on GFN's territories as a result of the Plan (e.g. impact on maintenance activities).
   - Amy Mikhaila acknowledged GFN had a concern with TC Energy and maintenance elements and asked whether there might be other concerns.
   - Nicholas Daube advised that a main interest of GFN is the impact of supply decisions regarding TC Energy's activities and operations on GFN's Territory (e.g. environmental risks, integrity digs) and GFN are interested in learning about opportunities for the First Nation participants to provide input

into the Plan. Nicholas Daube advised then that GFN desires more information and discussion around Enbridge Gas Inc.'s supply choice decisions, and more specifically, its decisions to source from TC Energy.

- Amy Mikhaila agreed that Enbridge Gas Inc. would reach out to TC Energy to share concerns, but recognized TC Energy is not obligated to share information given the commercial nature of the relationship.
- Amy Mikhaila noted that another takeaway could be outlining what other alternatives may be available to source gas instead of from TC Energy, if any.
    - Nicholas Daube agreed this would be useful information.
- Jennifer Mills asked how the planning cycle within the Plan ties into infrastructure planning.
    - Adam Stiers advised that planning is driven primarily by demand and emphasized that the gas supply planning team is distinct from other project focused teams.
    - Adam Stiers explained that the Plan team receives annual and design day demand forecasts and run simulations trying to determine whether the current infrastructure and supply is optimally sufficient to serve the demands identified, and if not, what action could be taken to adjust Enbridge Gas Inc.'s portfolio. The function and plan itself is a commercially focused procurement plan.
    - Adam Stiers advised that regarding the infrastructure portion, the determination of whether or not existing infrastructure is sufficient for future demands happens outside of the gas supply plan group.
- Daniel Vollmer asked if Enbridge Gas Inc. is open to describing the discussion held with the IWG about gas supply in the updated Plan to enhance transparency and accountability.
    - Diana Audino noted that the IWG meeting minutes are provided to the OEB and filed in the annual report and as such, would be on the record.
    - Amy Mikhaila confirmed Enbridge Gas Inc. would inquire whether these minutes could be included in the next Plan update.

3. IWG Expert Presentation on 2029 Rebasing Indigenous Engagement
    - Sarah Welch, an expert retained by the First Nation participants on the IWG, advised that she was asked to look at Enbridge Gas Inc.'s past customer engagement to see how future engagement with Indigenous Communities can be strengthened in rebasing.
    - Sarah Welch presented an overview of the report she had prepared including her recommendations, organized into 6 themes: Rights Holder Lens, Differentiated Engagement, Integration of Ongoing Engagement, Accountability & Trust, Upstream Participation, and Economic Reconciliation.
    - Sarah Welch's oral presentation generally tracked the details set out in her PowerPoint document entitled "Engagement Evaluation – From customer to rights holder", which is appended to these minutes.
    - Lauren Whitwham asked about the study methodology including who Sarah Welch met with to prepare the presentation.
        - Sarah Welch advised that she had met with the IWG representatives.
    - Gesiena Antuma sought, in response to Recommendation 3, any suggestions for how to conduct early engagements.
        - Sarah Welch suggested discussing directly with the Nations and continuing conversations within the IWG.

    - Rob Lukacs added that for MSIFN, this would be something consultation staff at MSIFN would like to facilitate internally and with the community and report back to Enbridge Gas Inc. and that capacity funding would be needed if this approach is taken.
    - Nicholas Daube offered that the first point of contact at GFN would be Zack Hamm.
    - Jennifer Mills advised that the contact at COTTFN would be the consultation department. The Housing department is also interested.
    - Rick Peters advised that CKSPFN could do data collection for their customers/potential customers on reserve to better inform the discussions.
- Gesiena Antuma asked if Enbridge Gas Inc. should try multiple ways of getting feedback or if there were concerns with this.
    - Rick Peters advised that there could be fatigue due to over surveying but believes doing one-on-one interviews would be successful.
    - Rob Lukacs confirmed that over surveying is an issue.
    - Sarah Welch offered that it would be important to know how each Nation would like to be engaged.
    - Lauren Whitwham also acknowledged Nation members living off-reserve who could be targeted with a survey and asked Sarah Welch for any suggestions. Sarah Welch offered to connect with David Coletto seeking ways to encourage off-reserve members to self-identify/ target them in engagement.
    - Diana Audino also suggested going to the Nations directly to reach out to their membership.
    - Nicholas Daube noted that the recommendations are a package to help better address questions.
    - Gesiena Antuma advised that parallel tracks are used for engagement with other groups.
- Gesiena Antuma sought clarification on the process for gathering feedback and asked if it was specific to Indigenous communities or broader engagement. Gesiena Antuma noted that the previous round of engagement gave respondents the option to receive a follow-up or not.
    - Sarah Welch confirmed this was specific to Indigenous communities and it would be their choice on how they wanted to be followed up with.
    - Rob Lukacs suggested it would be a record of consultation.
- For context, Lauren Whitwham noted that 20 communities are being served with natural gas from Enbridge Gas Inc.
- Lauren Whitwham and Gesiena Antuma agreed to have the teams work together to inquire and gauge interest.
- Nicholas Daube emphasized this should be a priority for the IWG.

4. Methane Measurement
    - Luna Munro presented the oil and gas methane partnership (OGMP) 2.0 self-assessment.
    - Luna Munro provided an overview of the OGMP 2.0 framework, maturity level, and challenges.
    - In the 2024 CSR, we give an overview of the work we have done to evaluate the OGMP 2.0 framework, including the pilot satellite study, which included Gas Transmission and Midstream (GTM) and Gas Distribution and Storage (GDS) participated. GDS is the applicable business unit to Enbridge Gas Inc.

- The Fugitive Emissions Measurement Plan (FEMP) was discussed in the Rebasing application and the Utility Earnings and Disposition of Deferrals Account Balances application (deferral application) submitted to the OEB.
- In 2023, Enbridge Gas Inc. filed a partial settlement with the OEB which required Enbridge Gas Inc. to develop a robust investigation plan on how to accurately measure fugitive emissions for specific Enbridge Gas Inc. assets (the Fugitive Emissions Measurement Plan - FEMP).
- Enbridge Gas Inc. retained Highwood Emissions Management to support FEMP and they developed the Highwood Report with recommendations.
- Peter Mussio advised that the Highwood Report looked at different technologies and found that satellite technology is not developed to the point where it can accurately detect the low level of emissions typically found on a distribution system. Vehicle mounted technology showed some promise.
- FEMP was submitted to the OEB as part of the deferral application, however the OEB did not believe FEMP would be a cost-effective activity and therefore did not approve the new deferral account that was requested for same. Based on the OEB's decision, Enbridge decided not to move forward.
- Luna Munro discussed opportunities to support measurement of fugitive emissions, including the amended federal Methane regulations.
- Luna Munro discussed Veritas, a standardized, science-based, technology-neutral, measurement-informed approach to calculating and reporting methane emissions.
- Emily Ferguson asked what the size of each grid square was for the pilot satellite study measurement and what the emissions intensity being looked for (would there be a certain level that would go undetected by satellite).
    - Peter Mussio confirmed to follow up with the answer.
- Emily Ferguson asked if the raw data of the pilot satellite study was available to be shared.
    - Peter Mussio to confirm.
- Rob Lukacs asked with regard to technology, if Enbridge Gas Inc. had consulted with Carbon Management Canada regarding methane detection and quantification testing.
    - Peter Mussio advised that there had been discussions with METEC to provide information in terms of quantification capabilities of various technologies.
    - Rob Lukacs asked if Enbridge Gas Inc. was looking at METEC's protocols with regards to established best practices for quantification.
        - Peter Mussio advised that they were looking at the Veritas protocol.
- Rob Lukacs requested more information on Veritas, why Enbridge Gas Inc. is funding the Veritas initiative and if Veritas offers auditing.
    - Peter Mussio advised that Enbridge Gas Inc. hadn't implemented Veritas methodology but could share an overview of the various protocols, which includes measurement and reconciliation. Peter clarified that Veritas doesn't perform the audits.
- Rob Lukacs sought confirmation if Enbridge Gas Inc. self-assesses maturity levels are stated in the Sustainability Report.
    - Peter Mussio confirmed that the OGMP 2.0 self-assessment included in CSR includes Enbridge Gas Inc.
- Rob Lukacs asked why Enbridge Gas Inc. doesn't externally audit the self-assessment.
    - Peter Mussio advised that there is no requirement to externally audit the self-assessment and the self-assessment was done to determine Enbridge Gas Inc.'s maturity level with the OGMP requirements.

    - Rob Lukacs advised that it would be important that Enbridge Gas Inc. communicate to stakeholders to be clear they aren't externally auditing these reports.
- Jennifer Mills asked what technology Enbridge Gas Inc. is using for continuously monitoring systems and the type of infrastructure it's appropriate for.
    - Luna Munro advised that they hadn't looked at all the technology options for the federal methane regulation Part 2 yet but are looking at technologies like electrochemical analyzers and lasers.
- Erna LeClaire asked if drones were used. Luna Munro responded that they had, but the technology reviewed to date will not work due to logistical issues.

5. Requested Changes to Environmental Report Terminology, Use of LiDAR for Archaeological Studies and Cumulative Effects Assessments
    - Kelsey Mills provided an overview responses to that were also provided by email on March 23 (See Attachment 4 – Requested changes to ER terminology):
    - Item 1. No questions from IWG.
    - Item 2. Jennifer Mills noted that the term mitigate could mean avoiding or extracting.
        - Kelsey Mills advised that Enbridge Gas Inc. first tries to avoid but if it comes to a point where there is an archaeology resource found, there is also the option to avoid further disturbance by rerouting the pipeline.
        - Rob Lukacs asked when rerouting would be given serious consideration.
            - Kelsey Mills advised that it depends on what the findings are; Enbridge Gas Inc. would try to limit disturbance to more significant finds such as burial sites, but that this does not happen frequently. Lauren Whitwham noted an example of this occurring before in the past.
            - Johanna Sanchez-Gomez advised that the licensed archaeologists also provide suggestions on how to manage situations.
    - Item 3. Stephanie Muller provided a summary of Enbridge Gas Inc.'s archaeology process.
        - Rob Lukacs asked how archaeology potential is determined for non-leave-to-construct (LTC) processes.
            - Kelsey Mills advised that a checklist for non-archaeologists, developed by the Ministry of Citizenship and Multiculturalism (MCM), is used. The checklist provides preliminary screening guidance and triggers for when an archaeologist should be retained to do a Stage 1 and/or 2 archaeological assessment (AA) if needed.
            - Rob Lukacs asked at what point would First Nations would be contacted for non-LTC process.
                - Lauren Whitwham advised that First Nations are invited to some Stage 2 AAs when in proximity to communities and areas of cultural significance and briefly outlined the process.
                    - Rob Lukacs advised that MSIFN would welcome the AA reports.
                - Enbridge Gas Inc. and MSIFN to discuss what level of information they would like to receive.
        - Jennifer Mills asked if there was anything within the checklists that explicitly discuss when a site would be avoided or excavated.

        - Kelsey Mills advised that Nations would have the opportunity to review the findings from the Stage 1 AA and voice opinions in the route determination process (for LTC process).
        - For non-LTC process, it would depend on the finding and Enbridge Gas Inc.
        - Johanna Sanchez-Gomez noted that the licensed archaeologist would also help identify next steps.
    - Rick Peters asked if the general archaeology process overview could be shared. Kelsey Mills confirmed it could. Rick Peters mentioned that workshops with the community are coming up and Enbridge Gas Inc. could possibly present this information.
    - Rob Lukacs asked if internal policies are going to change as a result of the new Ontario regulations.
        - Kelsey Mills advised that the documents are on a review cycle and would be updated to meet requirements of an updated Ontario Heritage Act.
- Item 4. No questions from IWG.
- Item 5. Jennifer Mills asked if the wording change from 'assets' to 'resources' was just for the presentation. Kelsey Mills advised it was but would also bring it to the archaeological consultants for consideration in archaeological assessment reports.
    - Zack Hamm noted that Indigenous communities are using 'ancestral belongings' or 'ancestral possessions' as the term.
        - Zack Hamm suggested looking to the communities for their preferred terminologies.
        - Lauren Whitwham asked what term would be used to describe tools. Zack Hamm advised that communities often refer to them as 'ancestral belongings'.
        - Jennifer Mills supported going to the communities for preferred terminology.
        - Kelsey Mills confirmed to take this discussion back to the archaeologists and discuss with communities.
        - Zack Hamm suggested including updated terminology in a terms of reference in reports.
- Item 6. Rob Lukacs advised that they would follow up on preferred archaeologist discussion. Lauren Whitwham noted that one of the IWG identified preferred archaeology firms was consulted for this response document.
    - Jennifer Mills expressed interest in receiving reports before they are added to the ER. Kelsey Mills advised that this could be done when the reports are available. Kelsey Mills noted that communities are also invited to attend the work that informs these reports. Kelsey Mills advised that these early opportunities to discuss are part of the updated process.
- Item 7. No questions from the IWG.

6. Next Meeting
    - Lauren Whitwham encouraged the IWG to attend in person and submit invoices.
    - Brent Bullough summarized outstanding agenda items, including rate harmonization, Brattle recommendations, winterization program, and an RSA update.

Action Items

1. Enbridge Gas Inc. to connect with TC Energy regarding concerns raised by Nations about their operations.
2. Enbridge Gas Inc. to present potential alternatives or scenarios for contracting with TC Energy for pipeline capacity.
3. Enbridge Gas Inc. to investigate including IWG minutes in future gas supply plan filing.
4. Oakview Advisory to inquire about suggestions for encouraging self-identification of off-reserve members on engagement surveys.
5. Enbridge Gas Inc. to gauge Nations' interest in rebasing discussions.
6. Enbridge Gas Inc. to provide the size of each grid square for the methane emissions satellite measurement and what the emissions intensity was being looked for.
7. Enbridge Gas Inc. to determine if the raw data from the pilot satellite emissions study can be shared.
8. Enbridge Gas Inc. and MSIFN to discuss the level of information/ reports to be shared with MSIFN for non-LTC work.
9. Enbridge Gas Inc. to share its general archaeology process overview with IWG.
10. Enbridge Gas Inc. to determine whether terminology used with archaeologists and communities can be refined to better align with Indigenous communities' expectations.
11. Enbridge Gas Inc. to circulate presentations that were provided during this meeting.

NEXT MEETING

Next meeting of the IWG is set to take place at the Enbridge Gas Inc. office at 500 Consumers Road North York, Ontario M2J 1P8 the first week of June, 2026. Team to canvas for an Agenda closer to the date and include previously suggested items.

APPENDIX A – AGENDA FOR MEETING OF IWG ON MARCH 23, 2026

Time	Matter	Participants
9:00-9:20 am	Safety moment, introductions, administrative matters, status of action items, approval of minutes	Brent Bullough and Group
9:20-10:20 am	Gas Supply Plan Update	Echo Xu and Adam Stiers

10:20-12:20 pm	IWG Expert Presentation on 2029 Rebasing Indigenous Engagement	Nicholas Daube and Gesiena Group
12:20-1:00 pm	LUNCH	
1:00-2:00 pm	Methane Measurement	Luna Munro and Peter Mussio
2:00-3:00 pm	Requested Changes to Environmental Report Terminology, Use of LiDAR for Archaeological Studies and Cumulative Effects Assessments	Kelsey Mills
3:00-3:15 pm	Wrap-up/Adjourn	Group

Distribution Integrity Management Program (DIMP) and Enhanced Distribution Integrity Management Program (EDIMP)

Report on Activities - 2025

ENBRIDGE
Life Takes Energy

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1. Overview

On August 17, 2023, the Ontario Energy Board (OEB) released its Decision on the 2024 Rebasing Phase 1 Settlement Agreement, in which the OEB approved the establishment of a new variance account for Distribution Integrity Management Program (DIMP) and Enhanced Distribution Integrity Management Program (EDIMP) costs.[1]

As part of the Decision, Enbridge Gas must provide annual reporting on actual DIMP/EDIMP spending, setting out the work done (and associated costs), listing the projects/facilities where work was done, describing what facilities work was deferred or avoided or otherwise impacted as a result and discussing the cost/benefit analysis of the DIMP/EDIMP work done during the past year.[2]

The actual DIMP/EDIMP spending in 2025 amounted to $13.189 million. This report describes the activities and work that comprised this spend. A breakdown of actual expenditures is shown in Table 1. This report also describes the long-term mitigation plans and actions arising from the quantitative risk assessments completed on the 2024 EDIMP inspected pipelines.[3]

[1] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, p.31.
[2] Ibid, p.56.
[3] EB-2025-0155, Exhibit G, Tab 4, Schedule 1.

Table 1

2025 DIMP/EDIMP Actuals Breakdown

Line No.	Description	2025 Actuals ($ millions)
	DIMP	
1	Admin	1.561
2	Investigations & Assessments	0.579
3	Pipe Inspections	0.271
4	Station Inspections	0.106
5	Regulator Set Inspections	0.870
6	DIMP Carryovers	0.007
7	Total DIMP	3.394
	EDIMP	
8	Admin	0.946
9	In-line Inspection (ILI)	7.818
10	Corrosion Survey	0.380
11	Digs (Validation)	0.423
12	Assessments & Consulting	0.233
13	EDIMP Carryovers	(0.004)
14	Total EDIMP	9.795
15	Total DIMP and EDIMP	13.189

2. DIMP and EDIMP Administration

The total costs to administer the DIMP and EDIMP portfolios amounted to $2.506 million. These costs primarily included Full Time Equivalent (FTE) positions, contractor positions, and employee expenses such as travel & accommodations (T&A), training/conferences and professional dues to support the DIMP and EDIMP portfolios.

3. DIMP Projects

DIMP Projects consist of five distinct work categories: Investigations & Assessments; Pipe Inspections; Station Inspections; Regulator Set Inspections; and DIMP Carryovers. The actual spend for these work categories in 2025 was $1.833 million.

3.1 Investigations & Assessments

a) Unscheduled Inspections: Eight unscheduled inspections and assessments were performed in 2025. The unscheduled inspections and assessments were completed across multiple assets, including:

- Assessing the condition of cased steel piping in Kenora;
- Completing a mainline valve records review to identify the make and type of valves to improve valve reliability models and analysis;
- Completing a steam line risk assessment to identify all steam line systems in Ontario. This assessment followed the National Transportation Safety Board (NTSB) findings on the 2023 West Reading, PA incident[4] involving a cracked Aldyl-A punch tee that resulted in fatalities and injuries;
- Completing a soil corrosivity assessment to determine the cause of a corroded and leaking steel gas main;
- Conducting a soil temperature survey in London to measure the temperature profile in the proximity of steam lines. The results were used to validate a model to assess the risk of steel gas mains in the vicinity of steam line systems;
- Performing aerial crossing inspections at 168 aerial crossing sites in Ontario to develop appropriate risk-informed mitigation plans for each location;
- Conducting Non-Destructive Examination (NDE) tests on a gas service to support the root cause analysis of a leak investigation; and
- Conducting inspections on exceptional services to determine and verify their status. Exceptional services are service pipe that have been disconnected from the gas meter, but are still energized with natural gas (i.e., inactive services). This work followed the release of the NTSB findings on the 2024 Youngstown, OH incident[5] that resulted in a fatality and multiple injuries.

[4] National Transportation Safety Board, "UGI Corporation Natural Gas-Fueled Explosion and Fire," Washington, 2025.
[5] National Transportation Safety Board, "Enbridge Inc. Natural Gas-Fueled Building Explosion," Washington, 2025.

b) Special Leak Surveys: There were five targeted special leak surveys completed in 2025 for the purposes of managing and controlling risk.
    - Suspect saddle fusions: Annual leak survey to monitor suspect saddle fusions as a method of risk control. There are approximately 430 active saddle fusions that are considered suspect because they were installed by a particular gas fitter that had one joint fail prematurely, indicating a potential prevalent procedural flaw during installation.
    - Aldyl-A pipe systems: Twice annual leak survey in each of Erin and Campbellford, as both communities have experienced historical crack failures on their Aldyl-A pipe systems.

c) DriscoPipe M7000/8000 Plastic Pipe Assessment: This work involved the performance testing of DriscoPipe M7000/8000 segments removed from the Ontario distribution system to better understand material behaviour and long-term performance, as Enbridge Gas continues to operate a population of this pipe material within the system. The pipe has a defect where the glycerol used in the manufacturing process can cause the outer layers of the pipe to laminate and peel when subjected to heat, thereby reducing the safe operating pressure of the pipeline system. The results of the performance testing will be used to develop a mechanical model to assess the remaining service life of existing assets and support quantitative risk assessments for this material.

d) Heavier Hydrocarbon Contamination on PE Pipe: Hydrocarbon contamination is a condition seen primarily in Southwestern Ontario where pock-marks are formed at joints on PE pipe during the fusion joining process. When this occurs, it is a code requirement that mechanical fittings are used in place of conventional or electrofusion fittings. This work aims to understand the impact of the formation of pock-marks on the integrity of fused fittings to determine if adjustments to the procedure when hydrocarbon contamination is identified can be made, which could influence future code revisions. The investigation includes field sampling combined

with a series of mechanical testing and optical microscopy.

e) Plastic Pipe Records Review: This work involved reviewing over 120,000 as-laid drawings and field notes associated with approximately 54,000 gas main assets installed prior to 1987 to capture plastic material types that were not previously recorded in the work and asset management system (WAMS). This work was necessary to verify the inventory of Aldyl-A polyethylene (PE) pipe in Ontario following the recent increase in industry incidents related to Aldyl-A PE pipeline systems. Having greater certainty on inventory will inform the broader strategy for managing the risks associated with Aldyl-A PE pipelines, which are known to be susceptible to brittle-like cracking.

3.2 Pipe Inspections

a) Isolated Steel Service & Risers: This inspection plan focused on steel service lines and risers that have the potential to be electrically isolated from a cathodically protected steel pipeline system. In the absence of cathodic protection, a higher likelihood of leaks from corrosion exists for steel pipe. The inspection verified if the service lines were electrically isolated and also validated the riser type, improving certainty on riser type inventories. The information obtained from the inspections will support mitigation plans for identified electrically isolated steel services and risers. A total of 7,150 isolated steel services and risers were inspected in 2025.

3.3 Station Inspections

a) Distribution Stations: This inspection plan focused on identifying potential hazards at distribution stations beyond those identified during routine operational and maintenance inspections. The condition of each station was assessed with a focus on the cathodic protection of below ground piping at the station. Other hazards were identified including: frost heave, flooding, vegetation interference, lack of barriers, and unauthorized third-party interference. This inspection information is used to provide a comprehensive assessment for inspected stations that support risk-

informed plans and prioritization. A total of 1,988 distribution stations were inspected in 2025.

3.4 Regulator Set Inspections

a) *Service Extensions*: This inspection plan was performed to validate the inventory of service extensions, perform a visual assessment of the above ground piping condition and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected. A total of 1,088 service extension inspections were completed in 2025.

b) Local and Remote First Cut Reg Sets: This inspection plan was performed to validate the inventory of this type of regulator set, identify potential hazards, perform a visual assessment of the above ground components for atmospheric corrosion, and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected. A total of 5,076 local and remote first cut regulator set inspections were completed in 2025.

c) >400 Series Regulator Sets: This inspection plan was performed to validate the inventory of this type of regulator set, identify potential hazards, perform a visual assessment of the above ground components for atmospheric corrosion, and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected. A total of 6,000 >400 series regulator set inspections were completed in 2025.

d) 200 & 400 Series Regulator Sets: This inspection plan was performed to validate the inventory of this type of regulator set, identify potential hazards, perform a visual assessment of the above ground components for atmospheric corrosion, and perform a pipe-to-soil measurement to determine if the below ground piping was adequately cathodically protected. A total of 5,718 inspections were completed in 2025 on 200 & 400 series regulator sets.

e) Bulk Meters: This survey was completed to identify potential bulk meter sites and to collect condition and compliance information. Historically, bulk meters may have been installed to facilitate preferred customer rates for multi-unit customers, however the transfer of asset ownership was not well documented, creating potential uncertainty on responsibility for maintenance activities, such as leak surveys and cathodic protection surveys. The results will be used to clarify asset ownership between Enbridge Gas and associated customers, as well as developing a risk mitigation plan for assets that require remediation. A total of 18 bulk meter inspections were completed in 2025.

3.5 DIMP Carryovers

DIMP carryover costs are residual costs for DIMP projects commenced in 2024 but not charged until 2025.

4. 2025 EDIMP Projects

EDIMP Projects consists of five distinct work categories: In-line inspection (ILI); Corrosion Survey; Digs (Validation); Assessments & Consulting; and EDIMP Carryovers. The actual spend for these work categories in 2025 was $8.849 million.

4.1 ILI & Digs (Validation)

Five pipelines within the EDIMP portfolio were selected for in-line inspection in 2025:

- NPS 20 Winston Churchill (Mississauga)
- NPS 20 Queensway (Mississauga)
- NPS 10 Sarnia North (Southwestern Ontario)
- NPS 10 Dawn West (Southwestern Ontario)
- NPS 12 Fisher Ave. (Ottawa)

In-line inspections were conducted using crawler tool technology. The total inspected length for each pipeline was determined by a combination of several factors including, but not limited to, pipeline length, pipeline sections, environmental conditions, number of corrosion areas, previous corrosion survey results, accessibility, and the selected ILI

tool. A summary of the 2025 EDIMP ILI results are shown in Table 2.

Table 2
2025 EDIMP ILI Results

Pipeline Name	NPS	Major Vintage	Length (km)	ILI Runs	Length Inspected (km)	% Inspected	Phase 1 Anomalies Identified(1)
Winston Churchill	20	1958	10.7	6	3.33	~31%	0
Queensway	20	1955	17.5	7	4.07	~23%	5
Sarnia North	10	1936	19.2	10	5.27	~27%	57
Dawn West	10	1941	10.6	6	2.81	~27%	0
Fisher Ave.	12	1958	6.1	5	2.51	~41%	1

Notes:
(1) Phase 1 anomalies are: Metal Loss (ML) ≥ 70% wall thickness (wt), ML failure pressure ratio < 1.15, dent >2% with stress concentrator, dent with ML >40% wt.

16 out of the 63 Phase 1 anomalies that were identified through in-line inspections across the five inspected pipelines were mitigated in 2025. The remediation of these Phase 1 anomalies was completed through integrity digs and subsequent repairs. The remaining 47 Phase 1 anomalies will be remediated in 2026 as part of a partial pipeline replacement project on the Sarnia North pipeline. A summary of the mitigation activities for each pipeline is described below.

- NPS 20 Winston Churchill: No Phase 1 anomalies were identified, and no integrity digs were issued for this pipeline. Tool validation was completed in conjunction with the NPS 20 Queensway integrity dig non-destructive examination (NDE) results.
- NPS 20 Queensway: A total of five integrity digs were executed in 2025 to remediate five Phase 1 anomalies. Only two of the integrity digs were charged to the EDIMP Program for the purposes of tool validation. Once tool performance was confirmed, the remaining three integrity digs were capitalized.

- NPS 10 Sarnia North: Overall, a total of six integrity digs were executed to remediate ten Phase 1 anomalies, with all integrity digs executed in 2025. The integrity digs were all capitalized, as tool validation had been previously completed for this pipe size.

  Due to the quantity and close proximity of the other 47 Phase 1 anomalies, an approximately 1.7 km NPS 10 steel gas main replacement project was initiated in 2025, with an expected completion date in 2026. The exact replacement length will be determined once suitable tie-in points are confirmed. The initial estimated capital cost of the replacement project is $5.6 million, pending confirmation of tie-in locations. The partial replacement project will be executed within the capital budget of the 2026 Asset Management Plan, and will not contribute any O&M spend to the 2025 DIMP Variance Account.

- NPS 10 Dawn West: No Phase 1 anomalies were identified, and no integrity digs were issued for this pipeline. Tool validation was previously completed for this pipe size.

- NPS 12 Fisher Ave.: One integrity dig was executed in 2025 to remediate the identified Phase 1 anomaly. The integrity dig was capitalized, as tool validation had been previously completed for this pipe size.

The number of ILI runs executed for each pipeline ensures that sufficient data was collected to support an evaluation of risk against established risk targets, considering for remaining uncertainty in the uninspected segments. The number of integrity digs executed captures additional NDE data to validate ILI crawler tool performance and support quantitative risk assessments (QRA) for each pipeline as required.

A QRA is being completed for each pipeline and evaluated against risk criteria to support a determination on whether each pipeline is fit-for-service (FFS) in the long-term. If it is determined that the existing pipelines are not FFS, temporary mitigation efforts are considered to bring the risk as low as reasonably practicable (ALARP) in the

short-term while alternatives to bring the pipeline(s) back into tolerable risk thresholds are evaluated. Long-term permanent mitigation strategies to bring a pipeline back into acceptable risk thresholds may include, among other options:

1. Risk mitigation activities such as increased operational patrols, pipe protection (e.g., concrete slabbing), pressure restrictions, increased signage, public outreach, etc.
2. Implementing an “inspect and repair” program for the entire pipeline
3. Completing a partial replacement of the pipeline based on unique strata with intolerable risk levels and practical considerations
4. Completing a full replacement of the entire pipeline
5. Combination of any of the above or additional situational alternatives

The feasibility of any potential alternative will be determined by confirming that the post-mitigation risk is within acceptable levels and the practical considerations of implementing the solution. Any potential feasible alternative will then be evaluated and compared on factors, such as:

- Public safety and residual risk
- Public disruption and nuisance
- Uncertainty in long-term outcomes
- Net Present Value (NPV) analysis
- Other considerations (potential for alternative fuels, longevity of asset, future unplanned work and associated hazards/risks, property damage, reputational risk, etc.)

The QRA and evaluation of any potential required alternatives is expected to be completed, on a prioritized basis, for each 2025 EDIMP inspected pipeline by the end of 2026. The work required to implement long-term mitigations is planned to begin in 2027. Once the evaluation of potential required alternatives is completed, Enbridge Gas will be able to better quantify the cost/benefit analysis of the 2025 EDIMP work and what

facilities work was deferred or avoided.

An update on the QRAs and resultant long-term mitigation recommendations for the 2024 EDIMP inspected pipelines are described in Section 5 of this report.

4.2 Corrosion Survey

This work category is for above ground surveys such as Cathodic Protection (CP) system surveys and non-intrusive pipeline assessments (NIPA).

The CP surveys were performed on high priority EDIMP pipelines considered for potential in-line inspection in 2026. These surveys are utilized in the planning phase of each ILI project to identify areas of potential concern. These surveys can also be used to obtain deeper insight into the CP system health on each pipeline and will likely be used, when possible, to support future risk assessment work.

CP surveys also provide depth of cover (DOC) information along the pipeline. This data is used to plan the ILI execution and can also be used as an input to the risk assessment.

CP surveys were performed on the following pipelines in 2025:

- NPS 12 Effingham St. (Niagara Region)
- NPS 12 Third Concession Rd. (Niagara Region)
- NPS 10 Bentpath Line (Southwestern Ontario)
- NPS 20 Sydenham Rd. (Hamilton)

NIPA is a new method of pipeline assessment using Direct Current Voltage Gradient (DCVG), Close Interval Potential Survey (CIPS), DOC, and Long Stand-off Magnetometry (LSM) in combination with machine learning algorithms that utilize a large database of ILI results for similar pipelines. NIPA was used for the first time in EDIMP for the following pipelines:

- NPS 20 Winston Churchill
- NPS 10 Dawn West

4.3 Assessments & Consulting

The Investigations and Assessments work category was focused on high priority EDIMP pipelines. A consultant was hired to perform a desktop study to produce an inventory of geotechnical and hydrotechnical areas of concern for the following pipelines.

- NPS 6 Dryden
- NPS 10 Bentpath Line
- NPS 12 Effingham St.
- NPS 12 Third Concession Rd.
- NPS 20 Sydenham Rd.
- NPS 4, 6, 8 & 10 Atikokan
- NPS 36 Mississauga Southern Link
- NPS 10 English River Lateral

The purpose of this work is to obtain knowledge and insight into the geohazards associated with each EDIMP priority pipeline and utilize the information in the Hazard Assessment completed for each individual pipeline. The Hazard Assessment is a crucial component of each individual Integrity Plan which assesses the condition of a pipeline to determine if it is fit-for-service in both the short- and long-term.

In addition to the pipelines mentioned above, the consultant also refined the results for five previously identified sites to support further risk assessment and decision-making processes.

This work category also included investigation into the QRA model and like-in-kind approach improvements utilized for EDIMP pipelines.

4.4 EDIMP Carryovers

EDIMP carryover costs are residual costs for EDIMP projects commenced in 2024 but not concluded until 2025.

5. Update on 2024 EDIMP Inspected Pipelines

When the 2024 DIMP and EDIMP Report on Activities was published, the QRAs for each 2024 EDIMP inspected pipeline had not been completed. The purpose of this section is to provide an update on the QRA results, describe any long-term mitigation plans, and quantify the cost/benefit analysis completed for each pipeline where applicable.

Five pipelines within the EDIMP portfolio were selected for in-line inspection in 2024. A summary of the QRA results, long-term mitigation strategy, and cost/benefit analysis for each pipeline is shown below:

- NPS 12 Wilson Ave.: The QRA identified the predominant threat to be corrosion risk. After accounting for the repairs made to remediate the Phase 1 anomalies, 7.2 km (~63%) of the pipeline was identified as high-risk in its current condition.

  Two comprehensive, plausible, and feasible solutions were identified that would effectively mitigate the high-risks of the pipeline to acceptable levels.The alternatives evaluated included either:

  1. A full replacement of the existing pipe (11.4 km of NPS 12 steel high pressure (HP)); or
  2. The implementation of an inspect & repair campaign on a 15-year frequency for the entire pipeline. This option also included a potential replacement project of approximately 500m of NPS 12 steel HP east of Allen Rd, the full extent of which would be confirmed by an ILI in 2027.

  The benefits and limitations of each option, including an NPV analysis, were assessed to determine the optimal long-term mitigation strategy. The recommendation following the evaluation of potential long-term mitigation

strategies was to proceed with the inspect & repair option, as this was the lowest cost option that met Enbridge's risk thresholds.

The NPV of the inspect & repair option ($31.9 million) was significantly lower than the NPV of the replacement option ($109.0 million). The incremental O&M required for the inspect & repair option will be recorded in the Asset Life Extension (ALE) deferral account for later recovery.

As the inspect & repair mitigation strategy defers or eliminates a potential capital replacement project in the Asset Management Plan, the resulting cost savings from ALE activities will be recorded on the OEB scorecard. For the NPS 12 Wilson Ave. pipeline, these savings are calculated as the difference in NPV between the inspect & repair option and the replacement option. This difference is $77.1 million, and will be recorded in the 2026 ALE scorecard metric.

- NPS 12 Martin Grove: The QRA identified the predominant threat to be corrosion risk. After accounting for the repairs made to remediate the Phase 1 anomalies, 3.0 km (~39%) of the pipeline was identified as high-risk in its current condition.

  Two comprehensive, plausible, and feasible solutions were identified that would effectively mitigate the high-risks of the pipeline to acceptable levels. The alternatives evaluated included either:

  1. Replacing ~5.1 km[6] of the existing 7.77 km of NPS 12 steel HP pipeline; or
  2. Implementing an inspect & repair campaign on a 15-year frequency for ~5.9 km[7] (~76%) of the pipeline

  The benefits and limitations of each option, including an NPV analysis, were assessed to determine the optimal long-term mitigation strategy. The

[6] Replacement scope includes all pipe installed prior to 2002.
[7] Inspect & repair scope includes all pipe installed prior to 2022.

recommendation following the evaluation of potential long-term mitigation strategies was to proceed with the inspect & repair option, as this was the lowest cost option that met Enbridge's risk thresholds.

The NPV of the inspect & repair option ($9.9 million) was significantly lower than the NPV of the replacement option ($44.2 million). The incremental O&M required for the inspect & repair option will be recorded in the ALE deferral account for later recovery.

As the inspect & repair mitigation strategy defers or eliminates a potential capital replacement project in the Asset Management Plan, the resulting cost savings from ALE activities will be recorded on the OEB scorecard. For the NPS 12 Martin Grove pipeline, these savings are calculated as the difference in NPV between the inspect & repair option and the replacement option. This difference is $34.3 million and will be recorded in the 2026 ALE scorecard metric.

- NPS 10 Sarnia South: A QRA was conducted to evaluate the reliability and risk of the NPS 10 Sarnia South pipeline considering corrosion and third-party damage threats to its pipeline integrity. However, insufficient data was available to accurately assess the risk of compression couplings and aerial crossings along the pipeline. Therefore, it was recommended that additional analysis be performed on these features to assess their risks before any risk-informed mitigation strategies are fully developed and implemented. These additional studies are expected to be completed in 2026, at which point an updated QRA will be performed for the Sarnia South pipeline. Following the updated QRA, potential long-term mitigation strategies will be evaluated, and Enbridge Gas will then be able to better quantify the cost/benefit analysis for this pipeline.

- NPS 8 Port Stanley: A QRA was conducted to evaluate the reliability and risk of the NPS 8 Port Stanley pipeline considering corrosion and third-party damage threats to its pipeline integrity. However, insufficient data was available to

accurately assess the risk of compression couplings and aerial crossings along the pipeline. Therefore, it was recommended that additional analysis be performed on these features to assess their risks before any risk-informed mitigation strategies are fully developed and implemented. These additional studies are expected to be completed in 2026, at which point an updated QRA will be performed for the Port Stanley pipeline. Following the updated QRA, potential long-term mitigation strategies will be evaluated, and Enbridge Gas will then be able to better quantify the cost/benefit analysis for this pipeline.

- NPS 8 St. Thomas: A QRA was conducted to evaluate the reliability and risk of the NPS 8 St. Thomas pipeline considering corrosion and third-party damage threats to its pipeline integrity. The entire St. Thomas pipeline was assessed as meeting acceptable risk thresholds, and was therefore deemed as fit-for-service. No further mitigative action is required for this pipeline.

  As this assessment eliminated a potential capital replacement project from the Asset Management Plan, it qualifies as an ALE activity eligible for recording on the OEB scorecard. The associated ALE cost savings will be recorded as the avoided direct capital costs that would otherwise have been incurred to fully replace the St. Thomas pipeline (4.41 km of NPS 8). These replacement costs were estimated at $5.4 million and will be included in the 2026 ALE scorecard metric.

Supplemental Storage and Load Balancing Information Report

2025 Annual Report

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Appendix 1 - Summary of Non-Utility Storage Balances

Appendix 2 - Actual In-franchise Deliverability Relative to Entitlements

Appendix 3 - Derivation of Load Balancing Costs Variance for 2025 - EGD Rate Zone

1. Introduction

1. This report supports the commitment(s) to report annually on inventory related to non-utility storage operations, on required deliverability each year and on decisions and actions taken by Enbridge Gas to meet in-franchise deliverability requirements above the base level of 4.0 PJ,[1] and on market-based storage (MBS) and load balancing costs.[2]

2. Non-Utility Storage Balances for 2025

2. In Union's 2013 Cost of Service Decision, the OEB directed Union to file a report similar to that ordered in the 2010 Earnings Sharing & Disposition of Deferral Accounts and Other Balances proceeding, to monitor the inventory related to non-utility storage operations. Appendix 1 shows the non-utility inventory balances for October and November of 2025.

3. During the 2025 injection season, the non-utility storage balance peaked on October 20, 2025, at 97.4% full, with a balance of 129.8 PJ compared to available space of 133.2 PJ. On October 31, 2025, the date to which the Company manages its storage balance, the non-utility balance was 93.8% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2025.

3.In-franchise Deliverability Requirements

4. In the 2024 Rebasing Phase 2 Settlement Agreement, Enbridge Gas agreed to report on required in-franchise deliverability each year, and on the decisions and actions taken by Enbridge Gas to meet in-franchise deliverability requirements that exceed in-franchise entitlements (maximum of 4 PJ)[3]. In 2025, in-franchise deliverability requirements did not exceed in-franchise deliverability entitlements and no action was required. Appendix 2 shows the actual in-franchise deliverability relative to entitlements.

[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p. 24.
[2] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, pp. 23-24.
[3] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, p. 24.

4. Load Balancing Reporting

5. As part of the Company's OEB-approved 2024 Rebasing Phase 2 Settlement Agreement, Enbridge Gas committed to report annually on its MBS[4] and load balancing costs. The 2024 Rebasing Phase 2 Settlement Agreement goes on to explain that starting with the Company's 2024 annual deferral and variance account disposition proceeding:

> …Parties can review and propose changes to the load balancing costs … even where such costs were previously disposed of through the PGVA, and Enbridge Gas will record any changes approved by the OEB accordingly.[5]

6. Load balancing is the practice of meeting seasonal changes in customer demand throughout the year. Enbridge Gas generally plans to meet load balancing requirements for sales service and bundled direct purchase (DP) customers through a combination of withdrawals from and injections into storage (cost-based and MBS) and purchases of gas supply.

7. The Union rate zones have sufficient cost-based storage to meet annual load balancing requirements on a stand-alone basis. In the Union South rate zone, bundled DP customers are responsible for managing their incremental load balancing requirements through their obligation to meet checkpoint balances at key winter and fall operational dates,[6] and semi-unbundled DP customers are responsible for managing the entirety of their load balancing requirements through their contracted allocation of storage services. The EGD rate zone does not have sufficient cost-based storage to meet annual load balancing requirements. Accordingly, Enbridge Gas uses a combination of storage deliverability (from cost-based and MBS), winter supply purchases, and third-party peaking services, to meet load balancing requirements for the EGD rate zone.

[4] See Exhibit D, Tab 1, Schedule 1.
[5] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1, Schedule 1, November 29, 2024, pp. 26-27.
[6] Enbridge Gas manages incremental load balancing requirements beyond the checkpoint balancing obligations for bundled DP customers in the Union South rate zone.

8. In the 2024 Rebasing Phase 3 Application,[7] Enbridge Gas requested approval of a Rate Harmonization Plan to harmonize rate zones, including certain rate design methodologies for the determination and recovery of storage and load balancing costs. As part of the 2024 Rebasing Phase 3 Settlement Agreement,[8] parties agreed, and the OEB accepted, to harmonize rates and services and to establish one rate zone for distribution costs and three rate zones for gas supply, storage and transportation costs. Enbridge Gas expects to implement the harmonized rates and services sometime in 2027 and will file an implementation plan as part of the 2027 Rates application. Until that time, Enbridge Gas continues to apply the rate design methodologies and practices for the determination of storage and load balancing related deferral and variance account balances in accordance with the approved rate setting frameworks in place since the amalgamation of EGD and Union in 2019.

4.1 Load Balancing Supply Purchases

9. In addition to storage, Enbridge Gas also relies on the flexibility inherent in its procurement processes and policy related to Dawn supply purchases as well as third-party peaking services to meet load balancing requirements for the EGD rate zone.[9] While the primary function of the gas supply purchases Enbridge Gas makes is for consumption by sales service customers and for use in the Company's operations, the timing of the supply purchases also assists with load balancing needs due to seasonal changes in bundled in-franchise customer's demand.

10. On a planned basis, supply purchased upstream of the franchise area is transported and delivered ratably throughout the year to the Company.[10] To manage load balancing requirements, planned Dawn supply purchases vary by month, with the largest planned monthly purchases occurring during the winter season. In addition,

[7] The proposed harmonized methodology for the derivation of load balancing costs is provided at EB-2025-0064, Exhibit 4, Tab 2, Schedule 2, Attachment 3.
[8] EB-2025-0064, OEB Decision on Settlement Proposal and Rate Order (March 26, 2026).
[9] Enbridge Gas can adjust the timing of planned Dawn purchases and make unplanned short-term Dawn purchases to adjust for variation to forecast or market volatility.
[10] Except for planned unutilized capacity.

unplanned load balancing requirements are largely met through unplanned short-term Dawn supply purchases.

11. On a planned basis as needed, Enbridge Gas may also plan for the purchase of third-party peaking services to manage load balancing requirements during near-peak and peak day conditions.[11] 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.[12]

12. 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]

[11] Peaking services are a third-party service arrangement that typically provide Enbridge Gas with the ability to call on the delivery of supply to a delivery area up to the contracted quantity for a maximum of 10 days per year.
[12] EB-2026-0092, 2026 Annual Gas Supply Plan Update, Section 3.6.
[13] Planned Dawn supply purchases for 2025 are from the 2024/25 gas supply plan (January to October) and 2025/26 gas supply plan (November and December).
[14] Enbridge Gas did not call on supply under contracted peaking services in 2025.

Table 1
2025 Dawn Supply Purchases

Line No.	Particulars (TJ)	EGD Rate Zone Planned	EGD Rate Zone Actual
		(a)	(b)
1	January	21,700	21,700
2	February	2,637	16,968
3	March	-	-
4	April	-	-
5	May	4,030	-
6	June	678	-
7	July	-	2,061
8	August	-	-
9	September	3,900	-
10	October	4,030	2,113
11	November	-	-
12	December	1,963	18,569
13	Total	38,938	61,411

14. Actual Dawn supply purchases were more than planned in 2025 due to colder than normal weather experienced. Enbridge Gas mitigated the impacts of colder than normal weather by making incremental un-planned supply purchases at Dawn to ensure it was able to meet storage inventory target(s).

15. The total cost associated with the Dawn supply purchases of 61.4 PJ was $310.2 million. Actual third-party peaking service demand costs were $0.04 million.

4.2 Load Balancing Costs

16. Load balancing costs of the EGD rate zone are recovered from customers through load balancing charges in base rates and the load balancing component of the Purchased Gas Variance Account (PGVA).

Load Balancing Charges

17. Prior to the amalgamation of EGD and Union, EGD rates were set through a Custom Incentive Rate-setting (IR) application. On an annual basis through the Custom IR rate setting mechanism, EGD updated costs and forecast volumes used to set base rates as well as updated gas supply costs to reflect the most recent gas supply plan. Upon amalgamation of EGD and Union, the approved rate-setting mechanism for the 2019 to 2023 period for the EGD rate zone changed to a Price Cap IR. Accordingly, the gas supply plan underpinning base rates was no longer updated on an annual basis.

18. As part of Enbridge Gas's 2024 Rebasing Application, base rates were updated to reflect updated forecasts, planning assumptions and revenue requirement impacts starting in 2024. In accordance with the Phase 1 Settlement Agreement,[15] 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. As part of Phase 3 of the 2024 Rebasing Application, parties agreed to harmonized rates that include an update to gas costs based on the 2024 gas supply plan.[16] Enbridge Gas expects to implement the harmonized rates sometime in 2027 and will file an implementation plan as part of the 2027 Rates application. Until that time, the gas supply plan in base rates for the EGD rate zone continues to reflect the gas supply plan and methodologies as approved in the 2019 Rates Application.[17]

[15] EB-2022-0200, Settlement Agreement, Exhibit O1, Tab 1, Schedule 1, August 17, 2023, pp.40-41. Parties agreed with Enbridge Gas's proposal for implementation of the 2024 Gas Supply Plan after the OEB's decision on relevant matters was issued, and for reflecting cost variances in gas supply deferral and variance accounts.
[16] EB-2025-0064, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, January 21, 2026, p. 13-14.
[17] EB-2018-0305.

19. The classification of costs as Load Balancing in the cost study for the EGD rate zone includes third-party peaking services,[18] Dawn supplies, and upstream transportation costs to meet the load balancing needs of sales service and bundled DP customers. For purposes of this report, Enbridge Gas will focus on the commodity costs included in base rates (i.e., peaking services and Dawn supplies).

20. Forecast commodity purchase costs are updated in base rates each quarter with the Quarterly Rate Adjustment Mechanism (QRAM) application to reflect future market prices over a 21-day period as per the OEB-approved methodology with variances recorded in the PGVA. 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 10^3m^3 (102.1 PJ) and peaking supply volumes of 6,902 10^3m^3 (0.3 PJ) based on the gas supply plan in base rates.[19]

21. 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).[20] Peaking services are classified 100% as load balancing - peak. The forecast load balancing costs are recovered from sales service and bundled DP customers through the load balancing charges. The allocation of load balancing costs to each customer class reflects cost

[18] EB-2017-0086, Exhibit G2, Tab 6, Schedule 2, p. 1.
[19] EB-2018-0305, Exhibit E, Tab 4, Schedule 3, pp. 1-2.
[20] Per the approved cost allocation methodology underpinning the 2025 QRAM applications.

causality and is based on load balancing needs of each customer class based on the gas supply plan in base rates.[21]

22. Table 2 provides the total load balancing costs updated each quarter with the QRAM including the forecast of Dawn and peaking supply purchase costs classified as load balancing.

[21] Per the approved cost allocation methodology underpinning the 2025 QRAM applications.

Table 2
2025 Load Balancing Costs in Rates – EGD Rate Zone

Line No.	Particulars ($000s)	2025 (1) Jan QRAM (a)	April QRAM (b)	July QRAM (c)	Oct QRAM (d)
1	Forecast Dawn supply purchases (10^3m^3)	2,649,848	2,649,848	2,649,848	2,649,848
2	Forecast peaking supply purchases (10^3m^3)	6,902	6,902	6,902	6,902
3	Empress reference price ($/10^3m^3$)	90.620	106.330	128.405	120.872
4	Dawn forecast price ($/10^3m^3$)	151.659	206.912	196.895	179.401
	Dawn Supply Purchases Classification				
5	System commodity supply (line 1 x line 3)	240,130	281,758	340,254	320,292
6	Transportation (2)	32,355	53,316	36,304	31,025
7	Load balancing - seasonal (2)	115,013	189,521	129,051	110,283
8	Load balancing - peak (2)	14,377	23,690	16,131	13,785
9	Total (line 1 x line 4)	401,874	548,285	521,741	475,386
	Peaking Services Classification				
10	Load balancing - peak (3)	3,242	3,183	2,921	2,973
	Load Balancing Costs in Rates				
11	Total load balancing commodity costs (lines 7 + 8 + 10)	132,632	216,395	148,104	127,042
12	Other load balancing costs (4)	45,961	44,578	45,657	45,945
13	Total load balancing costs in rates (5)	178,592	260,972	193,761	172,987

Notes:

(1) January 2025 QRAM (EB-2024-0326), April 2025 QRAM (EB-2025-0078), July 2025 QRAM (EB-2025-0165), and October 2025 QRAM (EB-2025-0244).
(2) Classification calculated as line 9 minus 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 costs plus demand costs.
(4) Other load balancing costs includes 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 Note 1 for the docket numbers of each QRAM application.

23. The determination of the changes in gas costs, including load balancing costs, through the QRAM process is mechanistic where Enbridge Gas updates the gas cost prices for the current QRAM and compares the total costs with the previous QRAM with the base rates adjusted for the difference. Enbridge Gas records the variance between actual and forecast gas supply purchase costs, including Dawn supply purchases, for past periods in the PGVA.

PGVA

24. 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.

25. The volume variance between the actual gas supply purchases and the forecast gas supply purchases to serve EGD sales service customers is recognized as a commodity variance in the PGVA. Commodity variance costs are allocated to sales service customers only per the approved QRAM methodology.

26. 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.[22] Load balancing variance costs are allocated to each customer class in the same manner as the allocation of load balancing costs in rates.

[22] The calculation of monthly variances can be found in QRAM evidence in Exhibit C, Tab 1, Schedule 2, pp. 3-4.

Appendix 1

Enbridge Gas Inc.

Summary of Non-Utility Storage Balances

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1-Oct-25	133.2	119.8	90.0%	1-Nov-25	133.2	125.6	94.3%
2-Oct-25	133.2	120.9	90.7%	2-Nov-25	133.2	126.3	94.8%
3-Oct-25	133.2	122.0	91.6%	3-Nov-25	133.2	126.7	95.1%
4-Oct-25	133.2	123.3	92.5%	4-Nov-25	133.2	127.4	95.6%
5-Oct-25	133.2	124.4	93.4%	5-Nov-25	133.2	127.9	96.0%
6-Oct-25	133.2	124.9	93.7%	6-Nov-25	133.2	127.9	96.0%
7-Oct-25	133.2	125.3	94.0%	7-Nov-25	133.2	128.3	96.3%
8-Oct-25	133.2	125.7	94.3%	8-Nov-25	133.2	128.6	96.5%
9-Oct-25	133.2	126.0	94.6%	9-Nov-25	133.2	128.7	96.6%
10-Oct-25	133.2	126.6	95.0%	10-Nov-25	133.2	127.9	96.0%
11-Oct-25	133.2	127.4	95.6%	11-Nov-25	133.2	127.5	95.7%
12-Oct-25	133.2	128.0	96.1%	12-Nov-25	133.2	127.0	95.3%
13-Oct-25	133.2	128.0	96.1%	13-Nov-25	133.2	126.8	95.2%
14-Oct-25	133.2	127.8	96.0%	14-Nov-25	133.2	127.3	95.5%
15-Oct-25	133.2	127.7	95.9%	15-Nov-25	133.2	128.4	96.4%
16-Oct-25	133.2	127.8	95.9%	16-Nov-25	133.2	128.7	96.6%
17-Oct-25	133.2	128.1	96.1%	17-Nov-25	133.2	128.7	96.6%
18-Oct-25	133.2	128.8	96.7%	18-Nov-25	133.2	127.9	96.0%
19-Oct-25	133.2	129.4	97.1%	19-Nov-25	133.2	127.2	95.4%
20-Oct-25	133.2	129.8	97.4%	20-Nov-25	133.2	126.8	95.1%
21-Oct-25	133.2	129.6	97.3%	21-Nov-25	133.2	127.1	95.4%
22-Oct-25	133.2	129.1	96.9%	22-Nov-25	133.2	127.9	96.0%
23-Oct-25	133.2	128.4	96.4%	23-Nov-25	133.2	128.6	96.5%
24-Oct-25	133.2	127.6	95.8%	24-Nov-25	133.2	129.1	96.9%
25-Oct-25	133.2	127.4	95.6%	25-Nov-25	133.2	129.9	97.5%
26-Oct-25	133.2	127.1	95.4%	26-Nov-25	133.2	130.6	98.0%
27-Oct-25	133.2	126.9	95.2%	27-Nov-25	133.2	130.8	98.2%
28-Oct-25	133.2	126.4	94.9%	28-Nov-25	133.2	130.7	98.1%
29-Oct-25	133.2	125.8	94.4%	29-Nov-25	133.2	130.6	98.1%
30-Oct-25	133.2	125.1	93.9%	30-Nov-25	133.2	130.4	97.9%
31-Oct-25	133.2	124.9	93.8%				

Appendix 2
Actual In-franchise Deliverability Relative to Entitlements

Line No.	Date	Actual In-Franchise Deliverability (TJ) (a)	Entitlement (b)	Remaining Deliverability (c)=b-a
1	1-Nov-25	249	4,000	3,751
2	2-Nov-25	132	4,000	3,868
3	3-Nov-25	399	4,000	3,601
4	4-Nov-25	163	4,000	3,837
5	5-Nov-25	637	4,000	3,363
6	6-Nov-25	502	4,000	3,498
7	7-Nov-25	539	4,000	3,461
8	8-Nov-25	648	4,000	3,352
9	9-Nov-25	1,656	4,000	2,344
10	10-Nov-25	1,423	4,000	2,577
11	11-Nov-25	1,284	4,000	2,716
12	12-Nov-25	518	4,000	3,482
13	13-Nov-25	995	4,000	3,005
14	14-Nov-25	868	4,000	3,132
15	15-Nov-25	904	4,000	3,096
16	16-Nov-25	1,173	4,000	2,827
17	17-Nov-25	1,502	4,000	2,498
18	18-Nov-25	1,481	4,000	2,519
19	19-Nov-25	1,375	4,000	2,625
20	20-Nov-25	817	4,000	3,183
21	21-Nov-25	712	4,000	3,288
22	22-Nov-25	908	4,000	3,092
23	23-Nov-25	769	4,000	3,231
24	24-Nov-25	728	4,000	3,272
25	25-Nov-25	764	4,000	3,236
26	26-Nov-25	971	4,000	3,029
27	27-Nov-25	1,551	4,000	2,449
28	28-Nov-25	1,787	4,000	2,213
29	29-Nov-25	1,386	4,000	2,614
30	30-Nov-25	1,978	4,000	2,022
31	1-Dec-25	1,753	4,000	2,247
32	2-Dec-25	1,508	4,000	2,492
33	3-Dec-25	1,659	4,000	2,341
34	4-Dec-25	1,936	4,000	2,064
35	5-Dec-25	1,327	4,000	2,673
36	6-Dec-25	1,020	4,000	2,980
37	7-Dec-25	1,595	4,000	2,405
38	8-Dec-25	1,927	4,000	2,073
39	9-Dec-25	1,499	4,000	2,501
40	10-Dec-25	1,291	4,000	2,709
41	11-Dec-25	1,643	4,000	2,357
42	12-Dec-25	894	4,000	3,106
43	13-Dec-25	1,472	4,000	2,528
44	14-Dec-25	1,997	4,000	2,003
45	15-Dec-25	1,606	4,000	2,394
46	16-Dec-25	747	4,000	3,253
47	17-Dec-25	270	4,000	3,730
48	18-Dec-25	-	4,000	4,000
49	19-Dec-25	697	4,000	3,303
50	20-Dec-25	277	4,000	3,723
51	21-Dec-25	710	4,000	3,290
52	22-Dec-25	218	4,000	3,782
53	23-Dec-25	-	4,000	4,000
54	24-Dec-25	-	4,000	4,000
55	25-Dec-25	410	4,000	3,590
56	26-Dec-25	1,034	4,000	2,966
57	27-Dec-25	885	4,000	3,115
58	28-Dec-25	174	4,000	3,826
59	29-Dec-25	1,091	4,000	2,909
60	30-Dec-25	1,088	4,000	2,912
61	31-Dec-25	1,224	4,000	2,776

Appendix 3
Derivation of Load Balancing Costs Variance for 2025 - EGD Rate Zone

Line No.	Particulars	2025 Actual Ontario Delivered Supplies (10^3m^3)	Forecasted Average Prices Empress (1) ($/10^3m^3$)	Actual Average Prices Empress (2) ($/10^3m^3$)	Average Price Variance Empress ($/10^3m^3$)	Commodity Cost Variance (3) ($000s)	Forecasted Average Prices Ontario Delivered (4) ($/10^3m^3$)	Actual Average Prices Ontario Delivered (5) ($/10^3m^3$)	Average Price Variance Ontario Delivered ($/10^3m^3$)	Forecasted vs Actual Price Variance Ontario Delivered (6) ($000s)	Load Balancing Price Variance ($000s)	Other Load Balancing Costs (7) ($000s)	Total Load Balancing Price Variance (8) ($000s)	Forecasted Peaking Costs (9) ($000s)	Actual Peaking Costs (9) ($000s)	Peaking Costs Variance (10) ($000s)	Total Load Balancing & Peaking Costs Variance (11) ($000s)
		(a)	(b)	(c)	(d) = (c)-(d)	(e) = (d)*(a)	(f)	(g)	(h) = (f)-(g)	(i) = (h)*(a)	(j) = (i)-(e)	(k)	(l) = (j)+(k)	(m)	(n)	(o) = (n)-(m)	(p) = (l)+(o)
1	Jan	555,275.2	89.043	104.842	15.799	$8,773.0	148.486	175.427	26.941	$14,959.9	$6,186.9	$46.9	$6,233.9	$296.5	$9.7	($286.9)	$5,947.0
2	Feb	434,173.7	95.617	104.941	9.325	$4,048.5	145.180	202.507	57.327	$24,890.1	$20,841.6	$9.4	$20,850.9	$296.1	$9.8	($286.3)	$20,564.6
3	Mar	4.5	82.062	96.603	14.541	$0.1	138.488	0.000	(138.488)	$0.0	($0.1)	$48.8	$48.7	$295.9	$9.7	($286.2)	($237.5)
4	Apr	4.7	85.465	107.698	22.233	$0.1	0.000	0.000	0.000	$0.0	($0.1)	$277.3	$277.2	$0.0	$9.7	$9.7	$286.9
5	May	2.0	79.753	99.940	20.188	$0.0	182.785	0.000	(182.785)	$0.0	($0.0)	($213.0)	($213.0)	$0.0	$0.0	$0.0	($213.0)
6	Jun	0.8	82.445	77.596	(4.850)	($0.0)	183.619	0.000	(183.619)	$0.0	$0.0	$58.4	$58.4	$0.0	$0.0	$0.0	$58.4
7	Jul	52,725.9	87.120	65.503	(21.617)	($1,139.8)	163.940	137.748	(26.191)	($1,381.0)	($241.2)	$111.1	($130.1)	$0.0	$0.0	$0.0	($130.1)
8	Aug	0.2	88.569	47.179	(41.391)	($0.0)	167.132	0.000	(167.132)	$0.0	($0.0)	($43.8)	($43.8)	$0.0	$0.0	$0.0	($43.8)
9	Sep	0.3	91.792	50.697	(41.095)	($0.0)	161.410	0.000	(161.410)	$0.0	$0.0	$25.0	$25.0	$0.0	$0.0	$0.0	$25.0
10	Oct	54,078.3	65.879	63.044	(2.835)	($153.3)	134.634	156.766	22.132	$1,196.9	$1,350.2	$74.8	$1,425.0	$0.0	$0.0	$0.0	$1,425.0
11	Nov	2.3	119.567	124.366	4.800	$0.0	160.848	0.000	(160.848)	$0.0	($0.0)	$19.2	$19.2	$0.0	$0.0	$0.0	$19.2
12	Dec	475,154.5	137.138	155.197	18.059	$8,580.6	187.035	231.285	44.250	$21,025.8	$12,445.2	$288.7	$12,733.9	$292.1	$0.0	($292.1)	$12,441.8
		1,571,422.4				$20,109.2				$60,691.7	$40,582.5	$702.8	$41,285.3	$1,180.6	$38.9	($1,141.8)	$40,143.5

Note

(1) Forecasted average prices at Empress = Forecasted Empress supplies costs / Forecasted Empress supplies volumes. EGD uses the Empress reference price to set the commodity rates
(2) Actual average prices at Empress = Actual Empress supplies costs / Actual Empress supplies volumes
(3) Commodity cost variance related to the actual Dawn purchases
(4) Forecasted average prices at Ontario Delivered = Forecasted Ontario Delivered supplies costs / Forecasted Ontario Delivered supplies volumes
(5) Actual average prices at Ontario Delivered = Actual Ontario Delivered supplies costs / Actual Ontario Delivered supplies volumes
(6) Purchase price variances for Dawn supplies recorded in the PGVA
(7) Other load balancing costs include un-forecasted LBA fees paid to the gas suppliers (e.g. TC Energy)
(8) Load Balancing Price Variance are the load balancing components that are disposed of the PGVA. Refer to the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, page 2.
(9) Peaking demand costs
(10) Peaking costs variance are the load balancing components that are disposed of the PGVA. Refer to the EGD QRAM schedule, Exhibit C, Tab 1, Schedule 2, page 2.
(11) Total load balancing costs variance are recovered or refunded from both system and direct purchase customers through the load balancing rate riders included in the QRAM

ENBRIDGE SUSTAIN BRAND CLARITY STUDY

1. Study Purpose and Context

1. As part of the 2024 Rebasing Phase 2 settlement proposal Enbridge Gas agreed to take reasonable steps in the next two years to study whether customers are confused between the utility and the competitive Enbridge Sustain affiliate, and what steps, if any, are appropriate to minimize or eliminate that confusion[1]. In relation to this commitment, the Parties do not agree about what jurisdiction, if any, the OEB has to address this matter but do agree that any such jurisdiction questions can be addressed, if necessary, after the report is filed [2].

2. This evidence discusses the "Brand Clarity" study (Study) undertaken by Enbridge Gas to fulfil the aforementioned commitment in the Phase 2 settlement proposal. The Study was undertaken to assess potential customer confusion between the utility and Enbridge Sustain. The Study can be found at Attachment 1 to this Exhibit.

3. Enbridge Gas contracted Ipsos LP, an independent third-party research firm, to conduct the Study. The Study was conducted using an online survey, with 2001 adult residents of Ontario from Ipsos' online panel. 47% of the sample self-identified as Enbridge Gas customers. The survey was fielded from October 14 to 16, 2025, with results weighted by age, gender, education, and region based on the latest census data to accurately reflect the adult population of Ontario.

2. Summary of Findings

4. The Study demonstrates that awareness of the Enbridge Sustain brand is very low among Ontario residents, including Enbridge Gas customers, and that the potential for brand confusion is correspondingly limited in scale.

[1] EB-2024-0111, Settlement Agreement, Exhibit N, Tab 1 Schedule 1, November 29, 2024, p.37.
[2] Ibid

5. Study results indicate that awareness of the Enbridge Sustain brand is low among Enbridge Gas customers and non-customers, at 6% and 5%, respectively. The absence of any meaningful difference between the two groups indicates that Enbridge Gas customers are not more likely to be aware of the Enbridge Sustain brand by virtue of being utility customers or being familiar with Enbridge Gas. These results can be found at Exhibit G, Tab 5, Schedule 1, Attachment 1, page 6.

6. Awareness and familiarity are closely connected, suggesting that recognition goes beyond awareness of the name, and extends to a sense of familiarity. Of the 6% of Enbridge Gas customers who are aware of the Enbridge Sustain brand, just over two-thirds (69%) report being at least somewhat familiar with the Enbridge Sustain brand. Among 5% of non-customers that reported awareness, fewer are familiar, at 43%. In absolute terms, these results represent a very small proportion overall. These results can be found at Exhibit G, Tab 5, Schedule 1, Attachment 1, page 8.

7. Though some respondents report familiarity with the Enbridge Sustain brand, awareness of the products and services actually offered by Enbridge Sustain is limited, and the levels of “don’t know” responses are high. This suggests that stated familiarity likely overstates actual knowledge of the Enbridge Sustain brand and its offering. Among Enbridge Gas customers, awareness of Enbridge Sustain’s products and services ranges from 17% to 20%. These results can be found at Exhibit G, Tab 5, Schedule 1, Attachment 1, page 11.

3. Conclusion

8. The Study shows that some brand confusion is observed between Enbridge Gas and Enbridge Sustain; however, given the low awareness, limited functional understanding of the Enbridge Sustain brand, and very small number of customers that are both aware and familiar with the Enbridge Sustain brand, any brand confusion is very limited in scale.

BRAND CLARITY SURVEY



ENBRIDGE

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Objectives & Methodology

Objectives

The primary goal of this research study was to assess potential brand confusion between Enbridge Gas, a regulated utility, and its affiliate, Enbridge Sustain, an unregulated energy-as-a-service business in Ontario. This survey explored the awareness of Enbridge Sustain among Ontario residents, including a group of individuals who self-identify as Enbridge Gas customers.

Methodology

Ipsos conducted an online survey with 2001 adult residents of Ontario utilizing the Ipsos pre-recruited iSay online panel. The survey was conducted between October 14th to 16th , 2025.

Results are weighted by age, gender, education, and region based on the latest census data to accurately reflect the adult population of Ontario.



Key Considerations

When interpreting this brand clarity survey, readers should be aware of several potential biases inherent to survey samples and brand association research, including:

- False-recognition bias: Respondents may claim familiarity with brands they have not actually encountered. This survey included two hypothetical brand names ("Enbridge Solutions" and "Enbridge Maintain") as controls. Awareness levels for these controls (17% and 6% vs. Enbridge Sustain's 6%) suggest that some reported awareness may reflect guessing or perceived familiarity with the "Enbridge" name rather than genuine recognition.
- Social desirability bias: Some participants may feel compelled to demonstrate knowledge rather than select "don't know" or "none of the above," which can influence how they respond to awareness questions.



Executive Summary

Brand Awareness

Awareness of Enbridge Sustain is very low at 6% among adult Ontarians and equally low among Enbridge Gas customers. By contrast, Enbridge Gas awareness is strong (71% overall; 89% among self-identified customers). Awareness of hypothetical brand names is on par with or higher than Enbridge Sustain, indicating a potential for false-recognition bias. **This indicates that current Enbridge Sustain awareness is almost non-existent.**

Familiarity with Enbridge Sustain

Among those who are aware of Enbridge Sustain, six in ten (61%) indicate that they are familiar with the brand. Familiarity increases slightly to seven in ten (69%) among Enbridge Gas customers, while less than half (43%) of non-customers who are aware of Sustain are also familiar with the brand. Given that only 6% of Ontarians and 5% of Enbridge Gas customers are aware of Enbridge Sustain, **the share of those who are both aware and familiar of the Enbridge Sustain brand is very small in absolute terms.**

Awareness of Products and Services

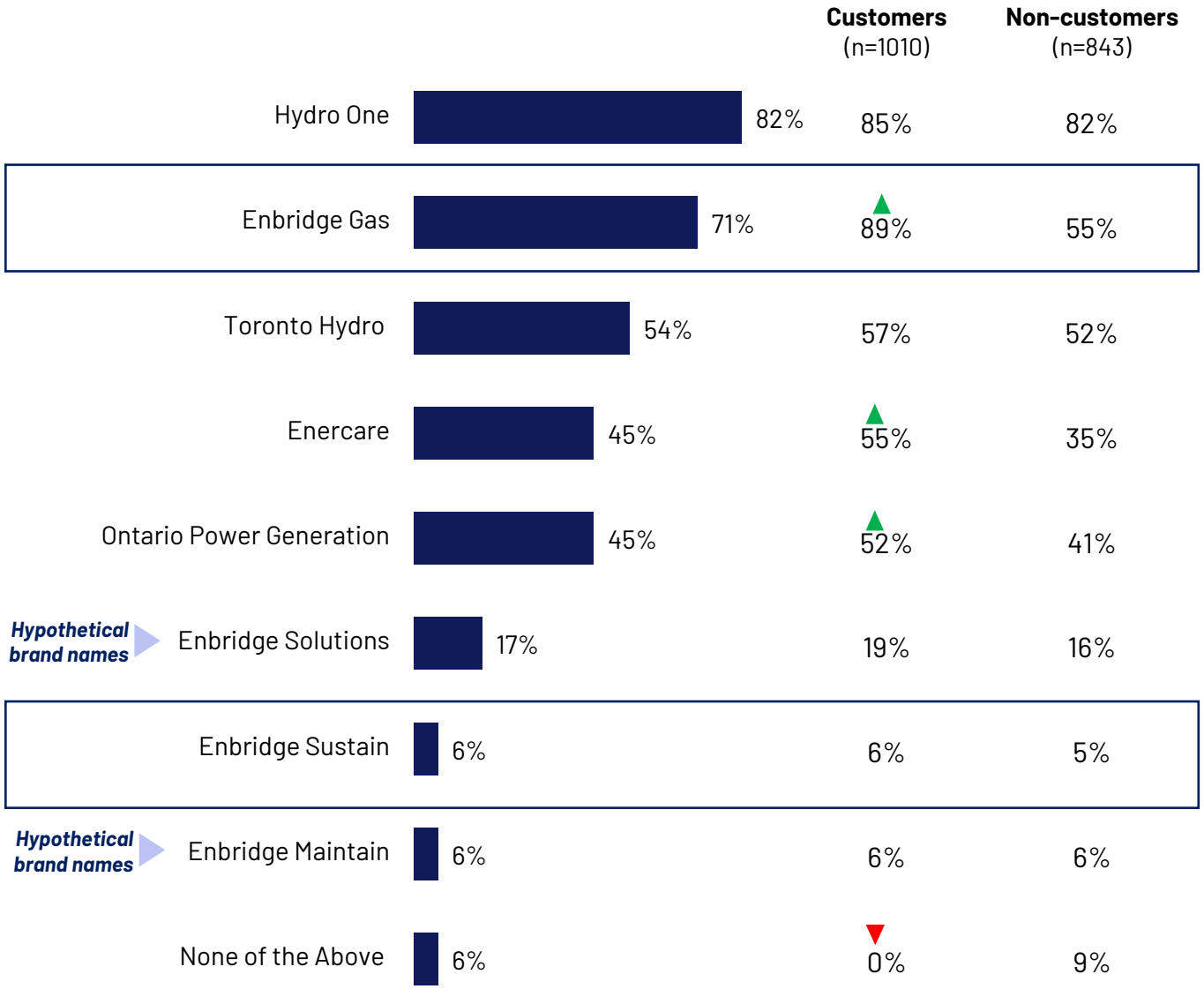
Results indicate low customer awareness of Enbridge Sustain offerings. Fewer than one in five customers correctly identify an Enbridge Sustain product or service, including home heating and cooling or water heater equipment and financing. **This suggests limited functional understanding of the Enbridge Sustain brand.**

KEY FINDINGS

Brand Awareness

- Only 6% of Ontario residents indicate that they are aware of the Enbridge Sustain brand. Awareness is equally low among Enbridge Gas customers (6%) and non-customers (5%).
- Two hypothetical brand names ('red herrings') were included in the survey to measure and compare awareness levels with brands that currently exist in the market. The findings show that awareness of these hypothetical brand names are on par or higher than the Enbridge Sustain brand, indicating that 'true' awareness is extremely low.
- Furthermore, those who are aware of the Enbridge Sustain brand also tend to be highly aware of the other hypothetical brand names, including Enbridge Solutions (77%) and Enbridge Maintain (61%), indicating the potential for false-recognition bias.

Brand Awareness by Enbridge Gas Customer Status



Base: All respondents (n= 2001)

Q1. Which of the following brands have you heard of? (Select all that apply)

*Note: The brand awareness question was asked prior to asking respondents if they are Enbridge Gas customers, to avoid biasing awareness responses.

Legend: ▲ upward green arrow = score is significantly higher than the comparative groups
▼ downward red arrow = score is significantly lower than the comparative groups

Comparing Awareness of Enbridge Gas and Enbridge Sustain by Demographics

- Both Enbridge Gas and Enbridge Sustain brands achieve the highest recognition in Central Ontario, yet other demographic patterns do emerge. Specifically, while Enbridge Sustain awareness persists at low levels across all subgroups, it is relatively higher among younger individuals aged 18-34 (9%), those with a higher education level (8%), and households with higher income levels (7%). In comparison, Enbridge Gas awareness is least among the younger demographic (48%), individuals with lower educational attainment (44%), and lower-income households (55%).

Awareness	Age			Gender		Region						Education				Household Income			
	18-34	35-54	55+	Male	Female	SW ON	East ON	Central ON	North ON	GTA 905	GTA 416	<HS	HS	Post Sec	Univ Grad	<$40K	$40K - <$60K	$60K - <$100K	$100K+
Aware of Enbridge Sustain (6%)	9%	6%	3%	▲ 7%	4%	5%	5%	▲ 10%	4%	5%	6%	-	5%	5%	▲ 8%	5%	▼ 3%	7%	7%
Aware of Enbridge Gas (71%)	▼ 48%	76%	83%	71%	71%	73%	68%	▲ 81%	60%	78%	66%	▼ 44%	69%	74%	75%	▼ 55%	72%	80%	80%

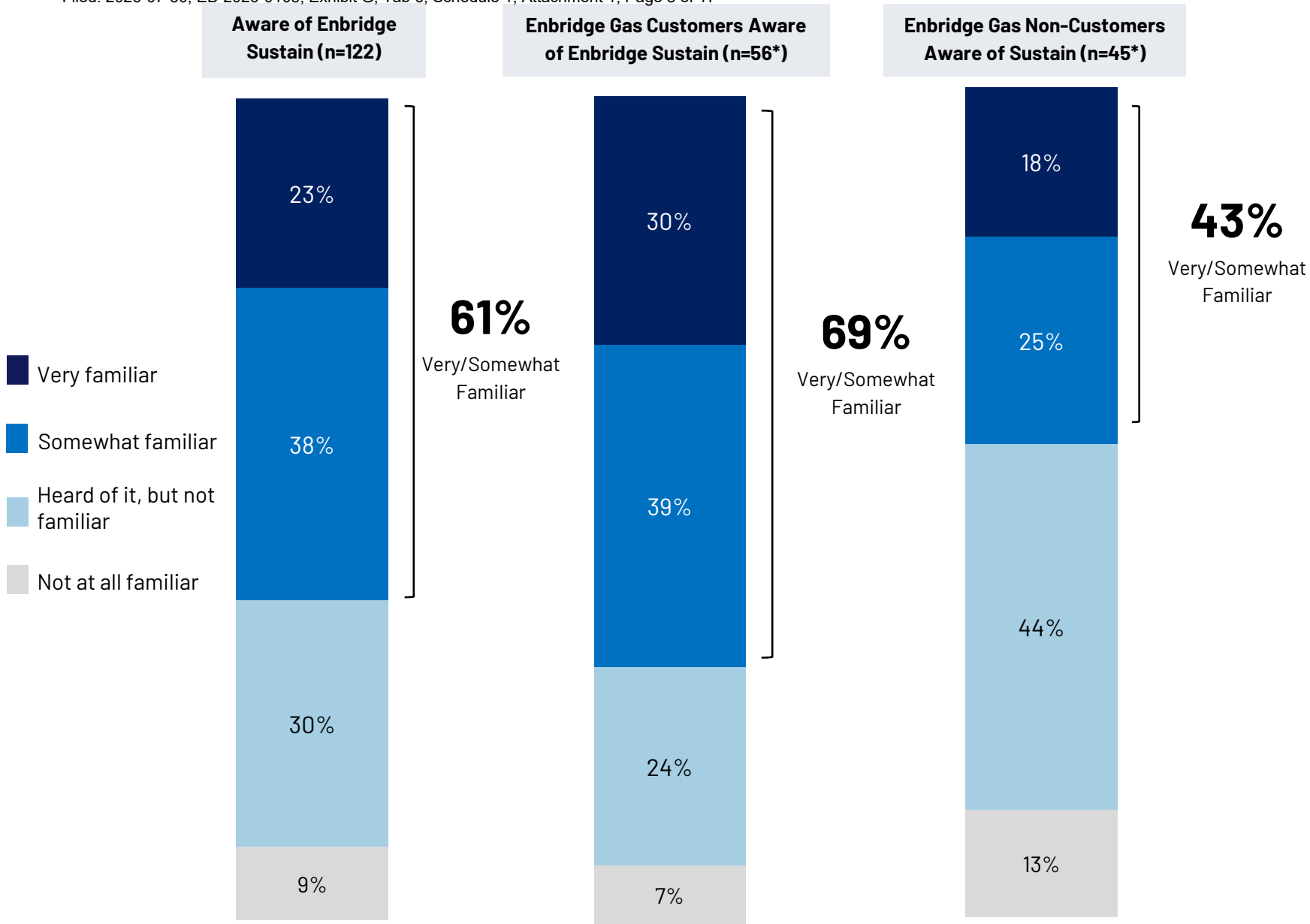
Base: All respondents (n=2001)
Q1. Which of the following brands have you heard of?
Number of respondents aware of each brand: Enbridge Sustain (122), Enbridge Gas (418).

Legend: ▲ upward green arrow = score is significantly higher than the comparative groups
▼ downward red arrow = score is significantly lower than the comparative groups

For region: higher or lower than 2 or more comparative groups

Familiarity with Enbridge Sustain

- While awareness of Enbridge Sustain is low at 6%, six in ten (61%) of those who are aware of Enbridge Sustain report being familiar with the brand, including 23% who are 'very familiar' and 38% who are 'somewhat familiar'.
- Among Enbridge Gas customers who are aware of Enbridge Sustain, seven in ten report familiarity, including 30% who are 'very familiar' and 39% who are 'somewhat familiar'. Note that the base size for this group is very small (n=56 respondents); thus, these findings should be treated with caution.
- Among those respondents who are not Enbridge Gas customers and who are aware of Enbridge Sustain, familiarity is slightly lower, although four in ten (43%) indicate that they are 'very familiar' or 'somewhat familiar' with Enbridge Sustain. Caution should be used when interpreting these results due to small base sizes.

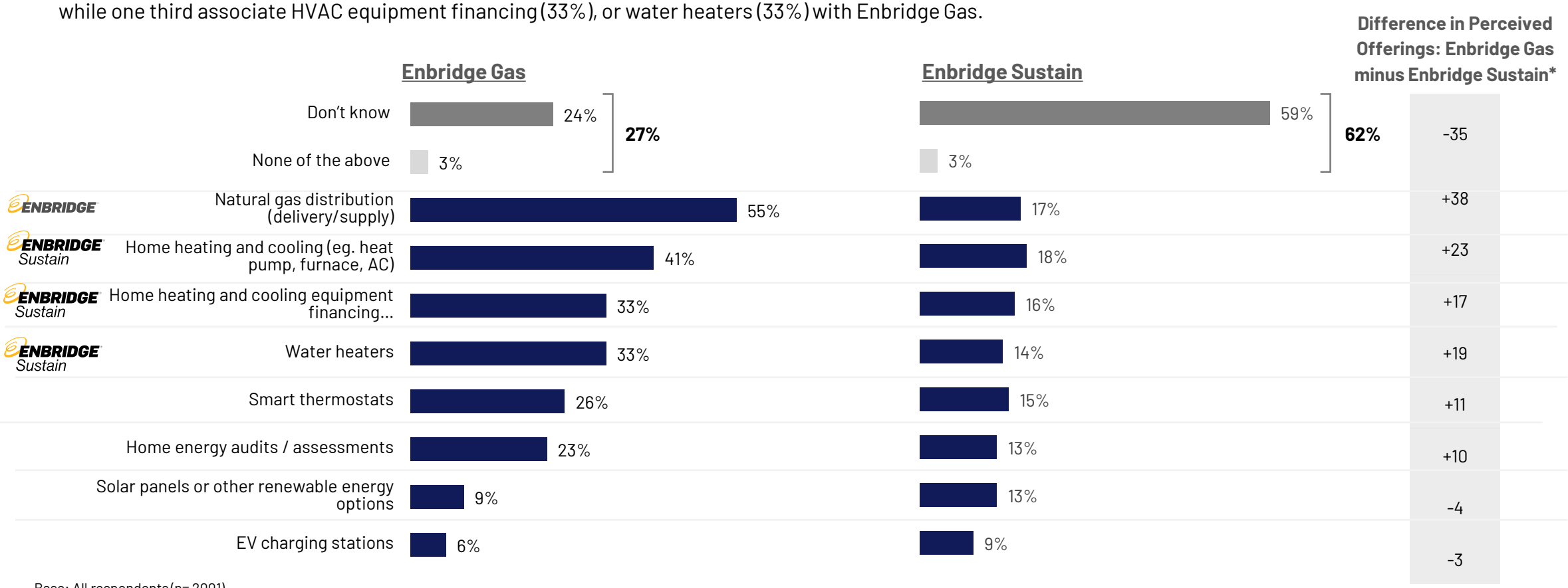


Base: n= 2001

Q2.How familiar are you with Enbridge Sustain? *Small base size, results should be interpreted with caution.

Awareness of Products and Services Offered by Enbridge Gas and Enbridge Sustain

- The majority (62%) of Ontarians do not know which programs and services are provided by Enbridge Sustain; among those who can identify a program or service, all options are mentioned equally. Some Ontarians attribute certain Enbridge Sustain offerings to Enbridge Gas - including 41% who associate home heating and cooling, while one third associate HVAC equipment financing (33%), or water heaters (33%) with Enbridge Gas.



Base: All respondents (n= 2001)

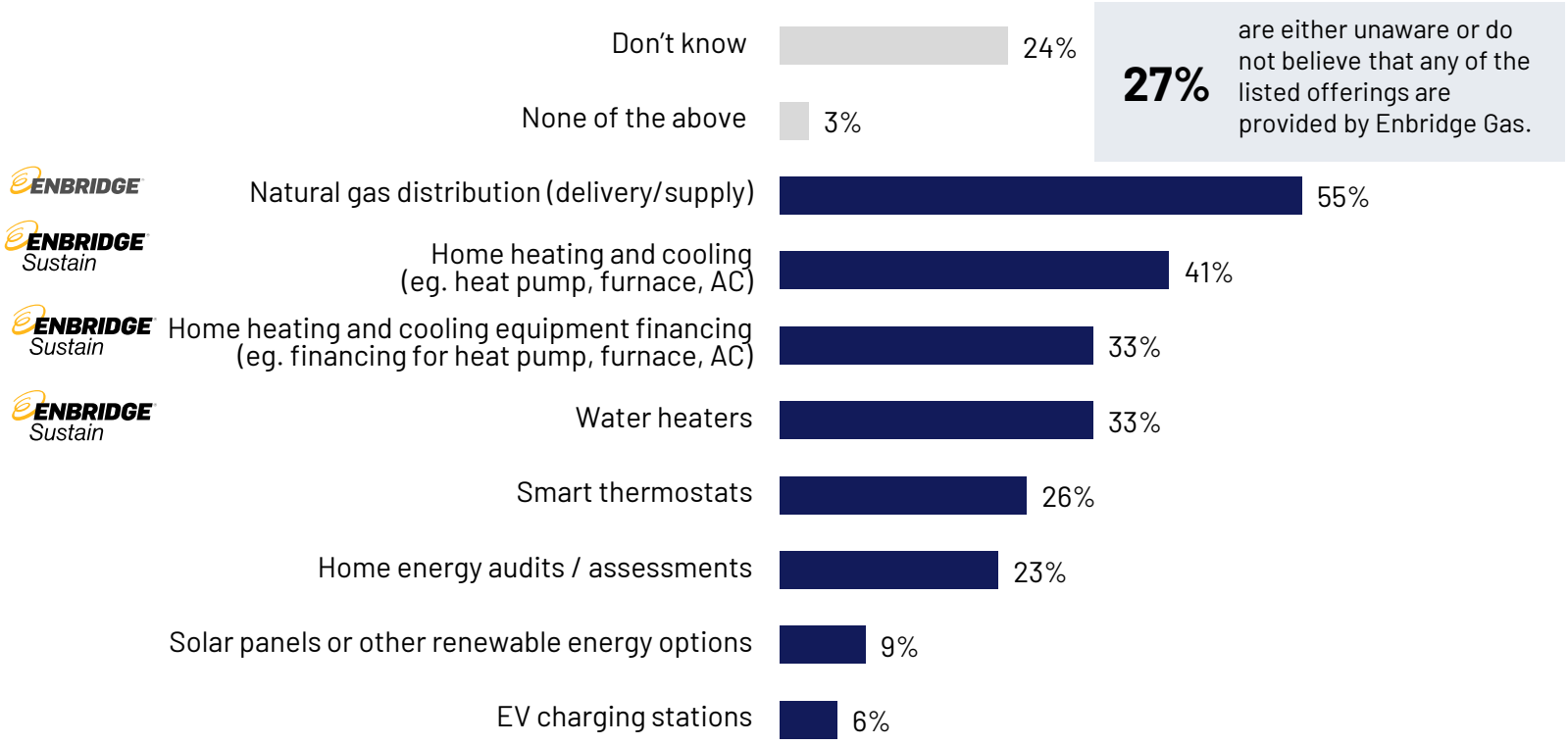
Q3. Which, if any, of the following products and/or services does Enbridge Sustain offer? (Select all that apply) / Q4. Which, if any, of the following products and/or services does Enbridge Gas offer? (Select all that apply)

*Note: Positive values in column on right side of page indicates perceived association with Enbridge Gas exceeds that of Enbridge Sustain, negative values indicate perceived association of Enbridge Sustain exceeds that of Enbridge Gas.

Awareness of products and services offered by Enbridge Gas

- Just over half of Ontarians (55%) correctly identify Natural Gas distribution as an Enbridge Gas service, a proportion that increases to 70% among Enbridge Gas customers, suggesting these customers have a clearer understanding of its primary offering.
- However, there is considerable confusion, with many incorrectly associating Enbridge Sustain services, such as Home heating and cooling (41%) and their financing (33%), and Water heaters (33%), with Enbridge Gas, suggesting a potential default to the better-known brand of Enbridge Gas. Further, this misattribution is somewhat more prevalent among Enbridge Gas customers (51%, 41% and 43% respectively). Even among those who are aware or familiar with the Enbridge Sustain brand, there is still misattribution of Sustain programs and services to Enbridge Gas, suggesting potential ongoing confusion between the two brands.

Products and services ENBRIDGE



27% are either unaware or do not believe that any of the listed offerings are provided by Enbridge Gas.

Enbridge Gas Customer	Awareness of Enbridge Sustain	Familiar with Enbridge Sustain
70%	76%	53%
51%	54%	41%
41%	50%	42%
43%	42%	36%
37%	35%	31%
29%	38%	30%
12%	28%	20%
8%	19%	15%

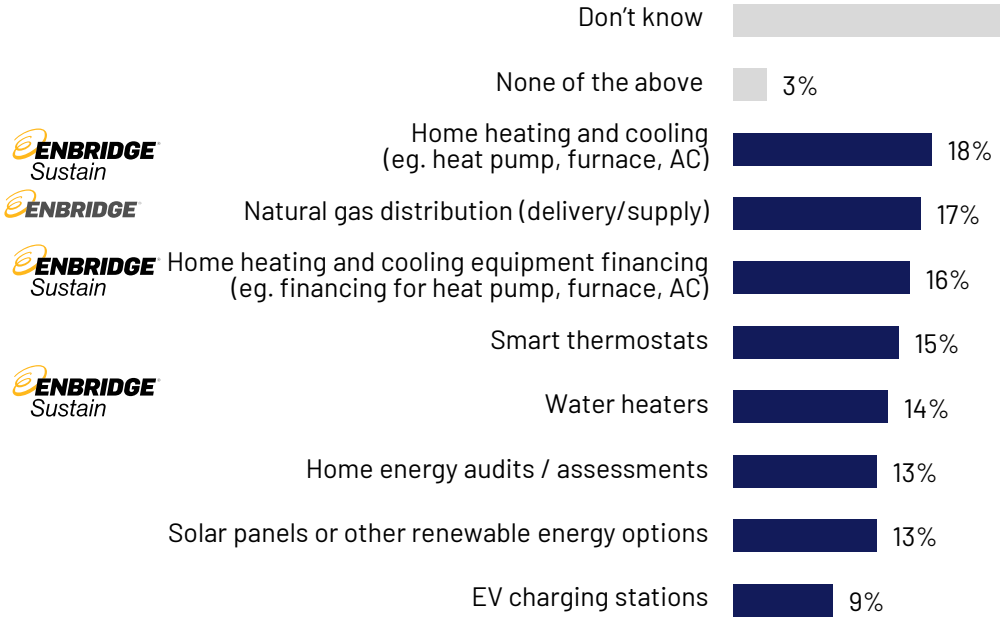
Base: n=2001

Q4. Which, if any, of the following products and/or services does Enbridge Gas offer? (Select all that apply)

Awareness of products and services offered by Enbridge Sustain

- Most Ontarians are unsure about the products and services provided by Enbridge Sustain. Fewer than 20% correctly identify an Enbridge Sustain product or service, although given that awareness of the brand is so low and association with all programs and services is constantly low, this indicates a low level of actual knowledge about what the Enbridge Sustain brand offers. Furthermore, 20% of Enbridge customers believe Enbridge Sustain provides natural gas distribution, which can also be interpreted as confusion with the Sustain brand.
- Attribution is higher among those who are aware or familiar with the Sustain brand; however, those programs or services actually offered by Enbridge Sustain do not stand out strongly in a significant way. Similarly, Enbridge Gas customers attribute Sustain programs and services at levels comparable to the general population.

Products and services ENBRIDGE Sustain



62%

are either unaware or do not believe that any of the listed offerings are provided by Enbridge Sustain.

Enbridge Gas Customer	Awareness of Enbridge Sustain	Familiar with Enbridge Sustain
20%	42%	43%
20%	34%	37%
19%	45%	42%
18%	42%	30%
17%	32%	36%
17%	33%	29%
17%	36%	29%
11%	32%	23%

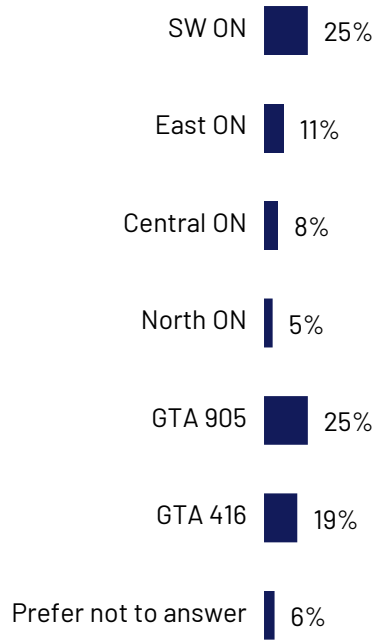
Base: All respondents (n= 2001)
Q3. Which, if any, of the following products and/or services does Enbridge Sustain offer? (Select all that apply)

DEMOGRAPHICS

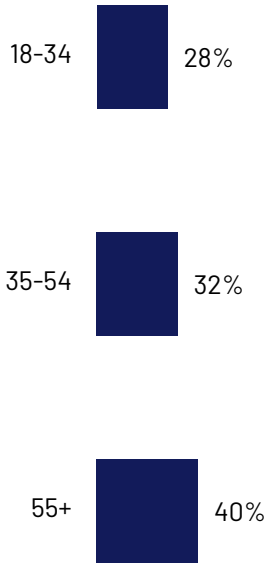


Demographics (1/3)

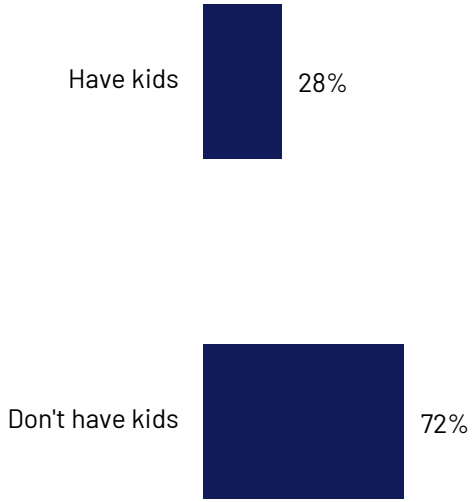
Region



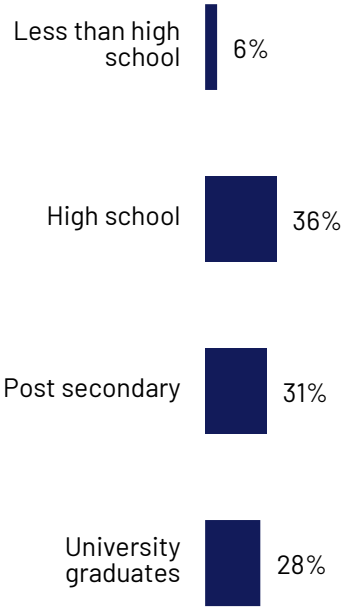
Age



Household composition



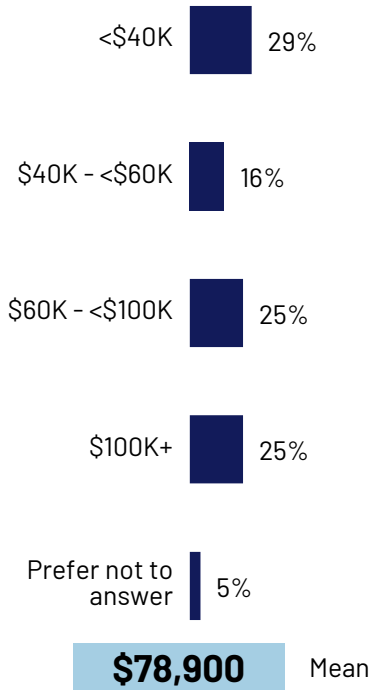
Education



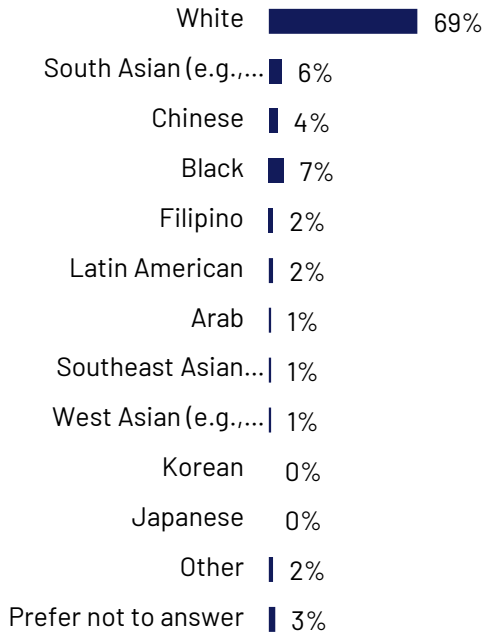
Base: All respondents (n= 2001)

Demographics (2/3)

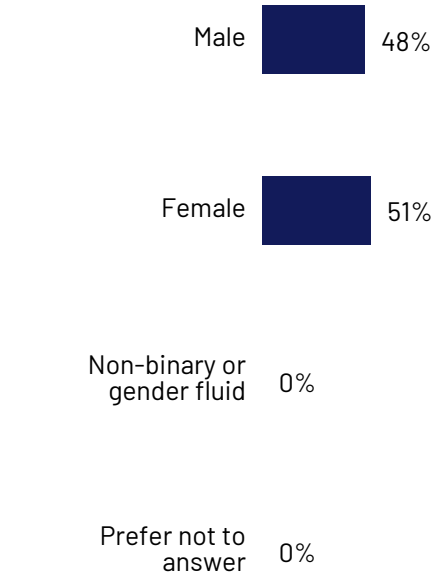
Income



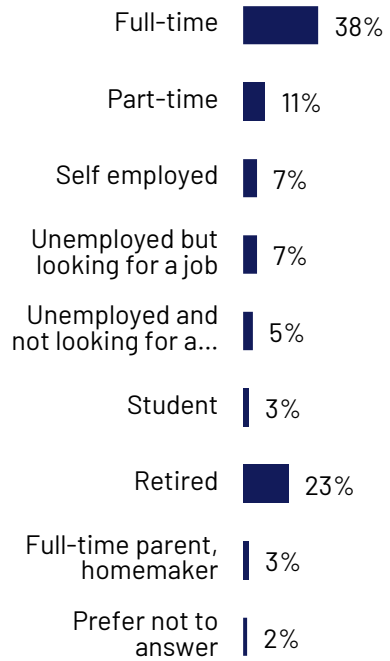
Ethnicity



Gender Identity



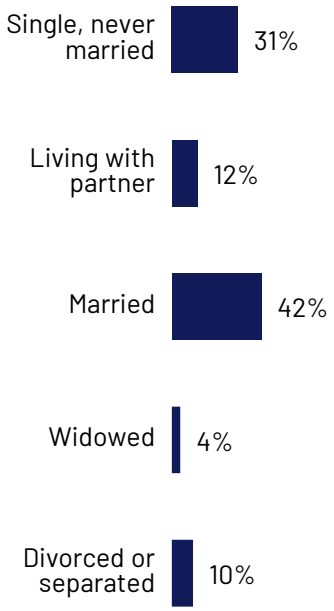
Employment Status



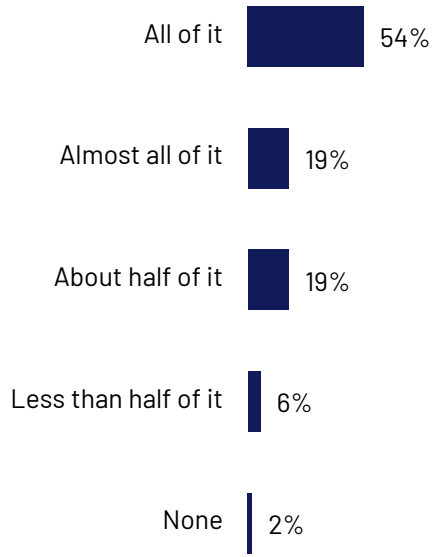
Base: All respondents (n=2001)

Demographics (3/3)

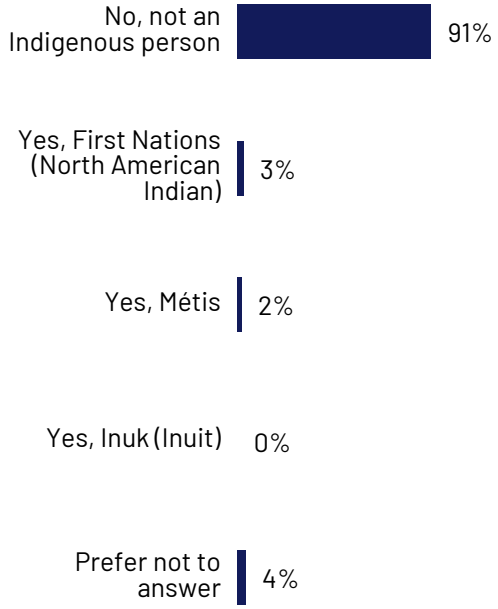
Marital Status



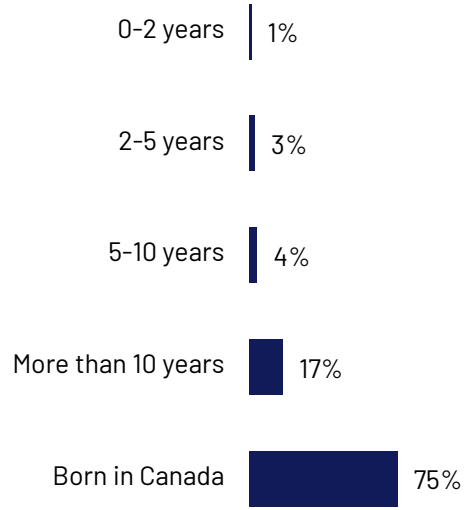
Household grocery shopping



Indigenous Identity



Length of Time in Canada

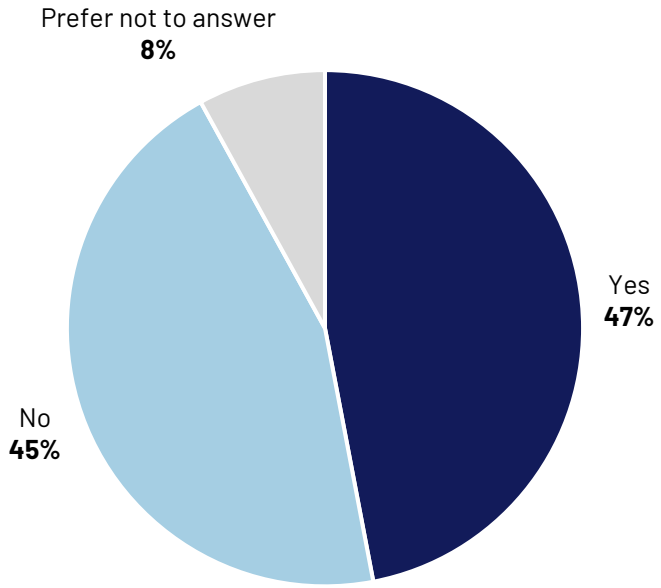


Base: All respondents (n= 2001)

Enbridge Gas Customers

Approximately half (47%) of those interviewed identify as Enbridge Gas customers.

Current Enbridge Gas Customers



Base: All respondents (n=2001)
Q5. Are you currently an Enbridge Gas customer?

THANK YOU

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